NBS-M009 - 2009

LOW CARBON BUSINESS REGULATION AND ENTREPRENEURSHIP

Handout 2

Sections 3 - 5

ENERGY FROM WASTE PLANT in JERSEY

Section 3 Electricity Markets Supply and Demand – Technical Issues
Section 4 Electricity Markets: Electricity Pool and Deregulation
Section 5 Electricity Markets: NETA and BETTA

15th September 2009

CONTENTS

5. ELECTRICITY SUPPLY and DEMAND – Technical Issues

3.1 Introduction

This section covers some general technical issues which need consideration in the generation, dispatch and supply of electricity. The section also includes some aspects to the structure of the electricity supply industry before privatisation. Sections 7 and 8 then cover a description of the Electricity Markets in the Privatisation era covering the Electricity Pool (Section 7) and NETA and BETTA in section 8.

3.2 Background to AC and DC.

In the early development of electricity supply, each town or city had its own power station to supply the needs of the local inhavitants. Supply was often as DC along thick low voltage conductors. The general consensus in the early part of the last century was that AC supply was to be preferred as the voltage could be changed much more readily and at almost any power level. This was an important development at the time as the losses through transmission are proportional to the current squared. However if the voltage is increased by a factor of 1000, this will redcue the current for the same power by a factor of 1000 and at the same time redcue the power losses by a factor of 1 million.

AC brought with it other problem such that the electrical load are not merely resitive (as with DC), but inductive or capacitative as well. In an inductive circuit, the voltage sine wave leads the current sine wave, while the reverse is true for a capacitiative circuit.

In a DC circuit the power dissipated in a load is merely the product of the voltage and the current

$$W = V \times I$$

Where V is the voltage
And I is the current.

In an inductive load the useful power is given by

$$W = V \times I \times \cos(ø)$$

Where ø is the phase angle between the voltage and current and may be negative or positive.

For an electric motor, the phase angle will typically be such that cos (ø) is approximately 0.8 with the current lagging. This implies that 20% of the useful energy is lost as reactive power. To compensate it is possible to place a capacitor across the terminals which will have the effect of compensating for the loss by reducing the phase angle towards zero. In early power factor corrector devices, this was the approach taken but there is limit to what can be achieved as under varying load the power factor will change.

Modern power factor correction devices tend to be electronic and can adjust automatically to changing phase angle shifts.

In long distance transmission the lines themselves induce reactive elemnts. Normally in daytime overhead liens will be inductive but at night time can sometimes by capacitative. On the other hand underground cable can be highly capcitative and very large losses indeed will arise in underground cables of even relatively short lengths. Throughout a transmission network there will be strategically placed inductors and capitors which can be switched in to compensate for phase angle shifts. Euqlly some generating statrions can be called upon to provide reactive power.

Long distance cables are particularly problematic with regard to losses and these are reduced significantly if DC transmission is used. However, there will be losses associated with the initial recifyer to DC at the input end and also the inverter at the output end. However these losses are constant, and thus over a certain length DC transmission has lower losses. Ac transmission losses can be reduced using additional cables, but then the cost goes up. In Ac transmission, the current tends only to flow in the outer part of the cable (the skin effect) whereas it flows through the whole cable in DC transmission.

3.3 Development of Electricity Supply Induistry in UK

By the 1930s, the demand for power was increasing rapidly and a move was taken to build regional larger power stations which in general were not close to main centres of population. This expanded under the British Electricity Authroity until the mid 1950s when the Central Electricity Generating Board took over responsibility for generation and transmission of electricity in England and Wales. The CEGB did not sell electricity to customers, but instead sold electricity to Regional Electricity Companies (see Fig. 3.1) who in turn sold to customers in their area only.

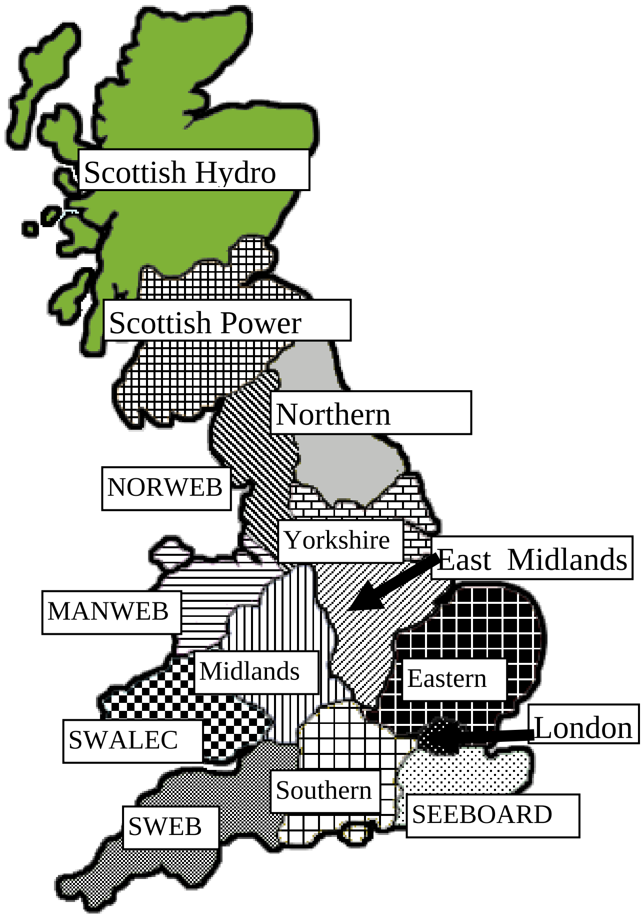


Fig. 3.1 Electricity Area Board pre-privatisation. The regions are still the same to this day, but are now owned by a variety of other companies – see Fig.

On 1st April 1990, Privatisation of the industry took place with the CEGB split into several successor companies but the Regionals Electricity Boards (or RECs) privatisated as individual units.

On the generating side, the key players immediately after privatisation were PowerGen and National Power an emrging markets of Independents, and Nuclear Electric, Scottish Nuclear, and Magnox Electric which remained in state controlled initially. The tranmsiion business of the CEGB was privatised as the National Grid Company who also became known as the Sytem Operator. Several subsequent changes took place in the 1990s. First Nuclear Electric and Scottish Nuclear were combined and privatised as British Energy with Magnox electric remaining the state control. Subsequently National Power was split into Innogy and International Power, and later both Powergen and Innogy were forced to sell a total of 6000 MW of generating capacity because of market manipulation. These station were purchased by Eastern electricity who then became and important player in the generation market. On the supply side there was little change in the structure of the regions with a few minor changes taking places such as East Midlands Electricity Board being acquired by PowerGen and in the North West Region and combined utilities company covering gas, water and electricity was established under the name United Utilities. Innogy had a trading name of nPpower which then acquired Midlands Electricity Board.

During the 1990s, electricity was traded via the Pool Mechanism as described in section 7.

Deregulation of Electricity Supply started with consumers over 1MW in 1990, expanded to include consumers over 100 kW in 1994, and finally to all consumers in a period starting between September 1998 and June 1999.

3.4 Predicting Demand and Dispatch in Nationalised Industry

Until privatisation, the CEGB were responsible for predicting demand and ensuring that demand was satisfied. The typical daily demand pattern in England and Wales in winter was as shown in Fig. 3.2, while the corresponding pattern in summer is shown in Fig. 3.3.

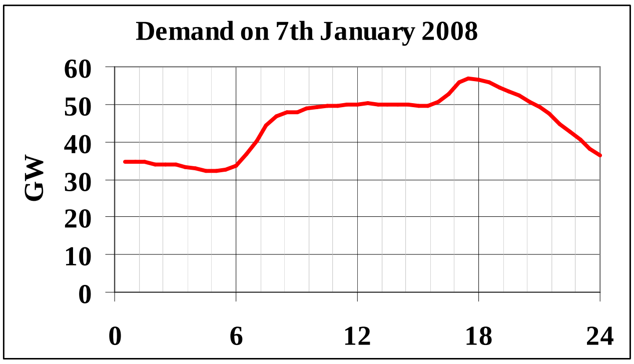


Fig. 3.2 Typical winter weekday (Monday) demand

For an up to date indication of actual currnet demand – consult http://www.bmreports.com which is also accessible from the Energy Web Pages. Details of demand as recently 30 minutes ago can be seen.

From 1st April 2005, Scotland joined England and Wales and data now displayed the demand for the whole of the three countries with the exception of Shetland, Foula, and Fair Isle. Fig. 6.4 shows actual data for 24th – 25th September 2008

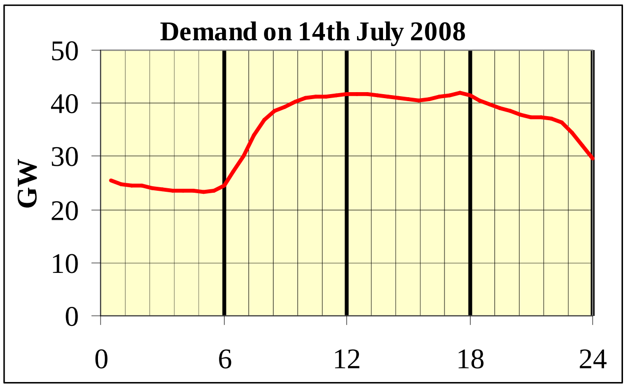


Fig. 3.3. Typical demand in summer on a weekday (Monday)

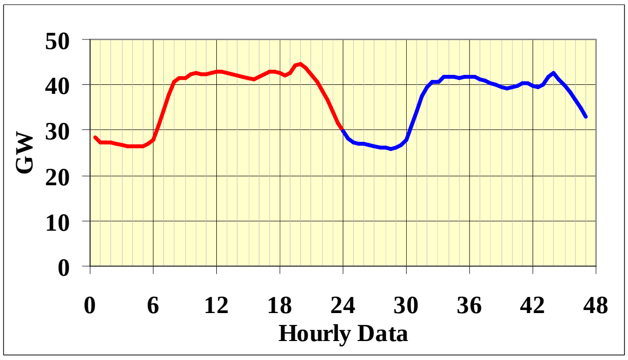


Fig. 3.4 Actual demand data for 24th – 25th September 2008. In winter the peak demand would reach to over 55 GW.

3.4.1 Forecasting Demand

Except in relatively small quantities. electricity CANNOT be stored, and generating capacity at any instant must be closely matched to demand. It is thus important to forecast demand as accurately as possible.

FACTORS AFFECTING DEMAND:-

- Weekdays have generally similar demand pattern to figures 3.2 – 3.4.
- Weekends have a different but generally consistent demand pattern.
- Minor variations occur:-
  e.g. larger morning peak on Mondays, more spread out evening peak on Fridays.
- Weather affects demand by shifting curve upwards:-

  *Dominant factors:-
  EXTERNAL TEMPERATURE (approx. 8% increase in heating demand for every 1^{o} C drop in temperature).
  INDUSTRIAL DEMAND (these are usually constant for a given day)
- Other factors:-
  * Wind chill
  * Solar gain
  - affect consumption by a few percent at most.
- Seasonal factors shift evening peak to late evening as daylight hours increase.

3.4.2 LEVELS OF FORECASTING

There are three levels of forecasting made by the National Grid Company – previously by CEGB pre-privatisation.

1) **LONG TERM:-** Strategic planning of requirements of period of years. In past CEGB used this for decisions on building of new plant. In early years after privatisation, long term strategic planning of new plant construction was left to market forces signalled by the "Value of Lost Load Parameter" – see section 7.4. More recently the National Grid Company has returned to 7 year statements and not infrequently announce warnings for follwoign winter if potential problems are forseen (e.g. recently in September 2008 regarding witner 2008 – 2009).

2) **SHORT TERM:-** (about 1 week ahead) on basis of long range weather forecasts to ensure sufficient plant is going available). It can take up to24 - 36 hours or so to bring some power station from cold to generating status although more modern stations are more flexible.

3) **24-HOUR FORECAST:-** (previous afternoon) on basis of latest weather information. This forecas*t **indirect***ly influences which generating plant are likely to be called upon in the coming 24 hours

On the basis of the above three, a projection is made for each half hour period in the following day. During the operation of the Electricity Pool from 1st April 1990 to 27th March 2001, the generating companies bid to supply electricity during a given period. This bidding process will be covered in detail later in the course.

After 27th March 2001, the New Electricity Trading Arrangements began and the predictions would be used by the generating and supply companies to establish their position by the time of Gate Closure (see section 8.3).

Fig. 3.5 shows the projected and actual demands for Saturday 27th - Sunday 28th September 2008.

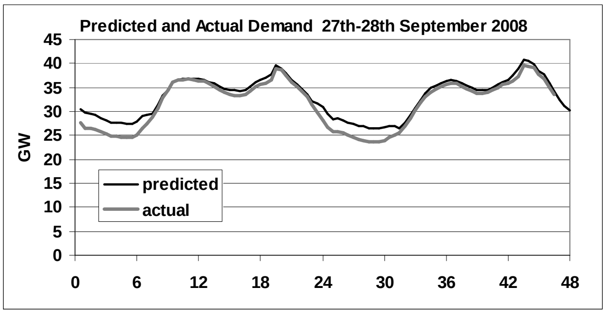


Fig. 3.5. Predicted and Actual Demands. The predictions were made 24 hours in advance. Note: note because of a System alert during period 45 on 28th September, there ere nodata for actual demand between 22:30 and 23:59 on 28th.

.

NOTE:-

i) A reserve of about 0.5 - 1.0% is usually provided by running generators slightly under full load. This gives scope for reasonable response in cases of emergency (e.g. failure of a 500/660MW generating set). Generators would be requested to have capacity available and synchronised.

ii) Forcasts are very difficult to do for special occaions: e.g. the Royal Weddings, as these occur rarely, and the demand in the early 1980's for which data is available would be different from a similar occasion now.

iii) **SPECIAL SPORTING EVENTS** can cause minor problems (e.g. the CUP FINAL going to extra time), but there is generally sufficient recent historical data to make reasonable predictions possible.

3.5 MEETING DEMAND - former CEGB method

Electricity cannot be stored except in small quantities so power stations are called into use as needed.

If a station is cold it may need up to1 - 2 days to come on line. Even when hot and synchronised most will need at least 20 minutes to come up to full power. A typical coal fired power station can rum up power at ~8 MW minute.

- Cheapest *marginal* plant were run first (i.e. nuclear -- does not mean nuclear is cheapest, merely that marginal cost is cheapest).
- Then came base-load Coal - most efficient coal.
  Above plant are run continuously for several days on end as demand is always above output (at least in short term)
- The cost for running a particular plant will depend on how warm the plant is (i.e. how long since last generation.

- **SHORT TERM FLUCTUATIONS:-** arising from equipment failures, television adverts etc. (i.e. periods of seconds to a few hours). These variations are dealt with by use of pumped storage schemes, use of GAS TURBINES etc and also by ramping up or down stations which are already synchronised but not at full load.

4. The Electricity Pool and Deregulation

4.1 Introduction

Following Privatisation on April 1st 1990, electricity was traded via the ELECTRICITY POOL. This system operated in England and Wales. Scotland had a separate system with vertically integrated electricity companies covering all aspects of electricity from generation through transmission, distribution, supply and finally metering. In Scotland there were two separate areas:

- Scottish Power covering the south of Scotland and covering the area formerly covered by the South of Scotland Electricity Board, and
- Scottish Hydro covering the north of Scotland (the area formerly known as the Scottish Hydro Board Area).

In England and Wales, there was no vertical integration and the CEGB was divded into several successor companies as shown in Fig. 4.1 The division of the generating capacity was done somewhat arbitrarily across the whole region of England and Wales.

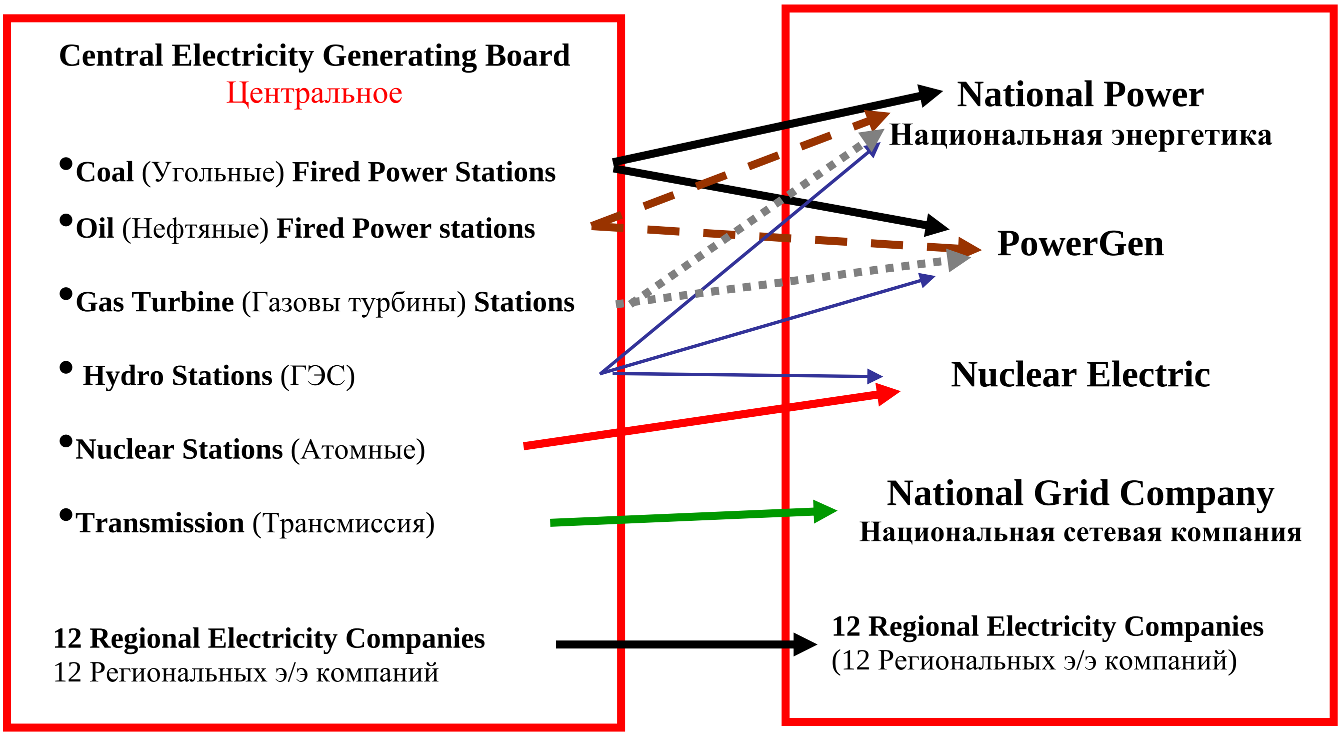


Fig. 4.1 Privatisation of Electricity Supply Industry in England and Wales on 1st April 1990.

The Market essentially consisted of the Electricity Pool into which generators bid to supply electricity. All generating units having a capacity of more than 100 MW had to bid into the pool to supply electricity, and this meant there were separate bids from each generating unit in a single station. The Pool evolved during the 1990s and by around 1998 the main generators involved in the Pool were:

National Power, PowerGen, Eastern group, Mission Energy, Nuclear Electric, BNFL (Magnox), "The Independents", Industry, and EdF. All these were involved in the "bidding process" described in section 7.2.

The suppliers as opposed to the generators then bought power from the Pool and sold it to customers in their area.

Scottish Power and Scottish Hydro did generate electricity for the Pool but supply in Scotland generally didi not go through the POOL as the companies were vertically integrated..

Purchasers of Electricity from the POOL were the Regional Electricity Companies included:-

- Regional Electricity Companies (e.g. MANWEB, SEEBOARD, SWALEC, YEB, NEB, EMEB, MEB, EMEB, LEB, SWEB, NWEB, Eastern Electricity, Southern Electricity).
- Licensed Suppliers

Several of these RECs were involved in take-overs and mergers in the late 1990s – for instance East Midlands Electricity became part of PowerGen, and Midlands became part of the nPower Innogy group, while NWEB was amalgamated with North West Water to form United Utilities, and Scottish Hydro and Southern have merged. Eastern purchased several power stations from PowerGen and National Power in 1998 and becasme one of the major generators.

4.2 Operation of the Electricity Pool

Fig. 4.2 shows a schematic of the players in the Electricity Pool

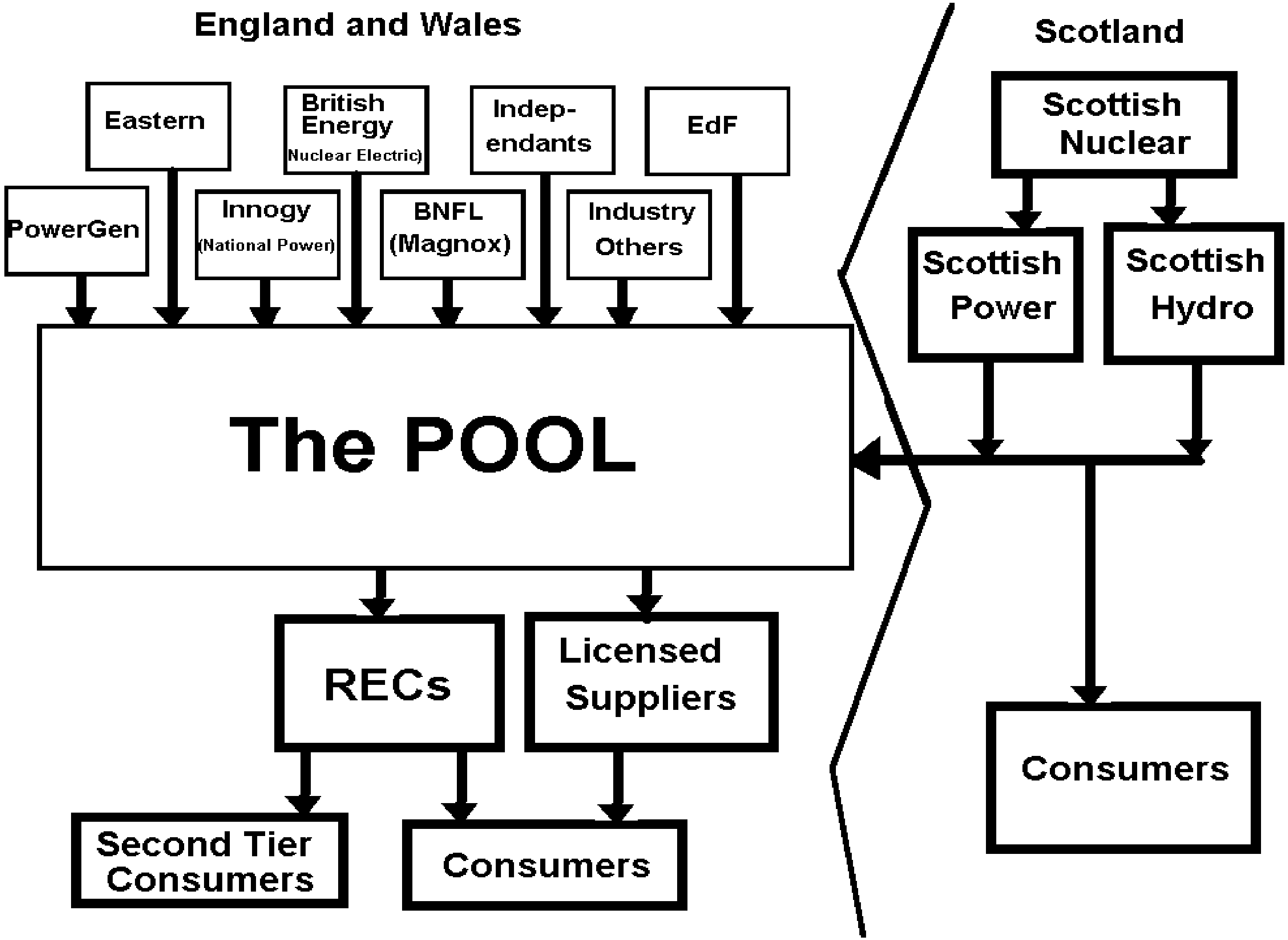


Fig. 4.2. A schematic representation of the Pool as it was in around 1998.

The situation to the left of the vertical dividing lien represented the situation in England and Wales, while that to the right represented the position in Scotland which was not affected by the Pool. Fig. 7.2 represents the situation with the Pool at around 1998 following the sale of 6000 MW of generating capacity to Eastern Group by both PowerGen and Innogy nPower, following fines by the regulator OFFER (Fooice of Electricity Regulation(at the time – now OFGEM (Office of Gas and Electricity Markets which was formed by the merger of OFFER and OFGAS).

The key generation players bidding into the POOL were the big 3 – i.e. PowerGen, Innogy nPower and Eastern Group, the two Nuclear Companies – Nuclear Electric and Magnox Electric, Large industrial generators, several Independent Electricty Producers, and finally Electricité de France (EdF).

In Scotland, Scottish Nuclear supplied electricity to the two Scottish Generators, Scottish Power and Scottish Hydro who then also bid into the England and Wales Pool.

The Electricity Pool set two prices of electricity via a bidding processes.

i) Pool Input Price or PIP was the results of a bidding process by the generators as explained in section 7.4.
ii) Pool Output Price or POP which was paid by electricity suppliers as they purchased electricity from the Pool. The difference between PIP and POP allowed for the cost of operation of the POOL including any sub-optimal dispatch of electricity as described in section 7.5

From the POOL there were three types of supplier to the customer.

i) The local Regional Electricity Company (REC) who covered a specific geographic region
ii) Second Tier RECs. A second Tier REC referred to the supply of electricity by a REC in an area other than their regional base. This became more prevalent following Deregulation (see section 7.).
iii) Licesensed Suppliers with no regional base. These companies became more prevelant following deregulation in 1998 – 1999 (see section), and might be companies supplying electricity to special interest groups irrespective of where the customer may be based – e.g. memebers of a Trades Union etc..

4.3. The Bidding Process

Each day the NGC published the expected demand for electricity for each half hour period during the following day, and invite bids from all generators who supply more than 100MW.

These bids had to be in by mid afternoon after which NGC decided who would generate (and hence get paid).

Each generator bid for each separate generating set (there may be four or more in a single station) and the bid will represent the total cost for running the plant (not just the marginal cost as in the case of pre-privatisation days. These bids were then stacked with the lowest bid at the bottom and successively higher bids above as shown in Fig. 4.3.

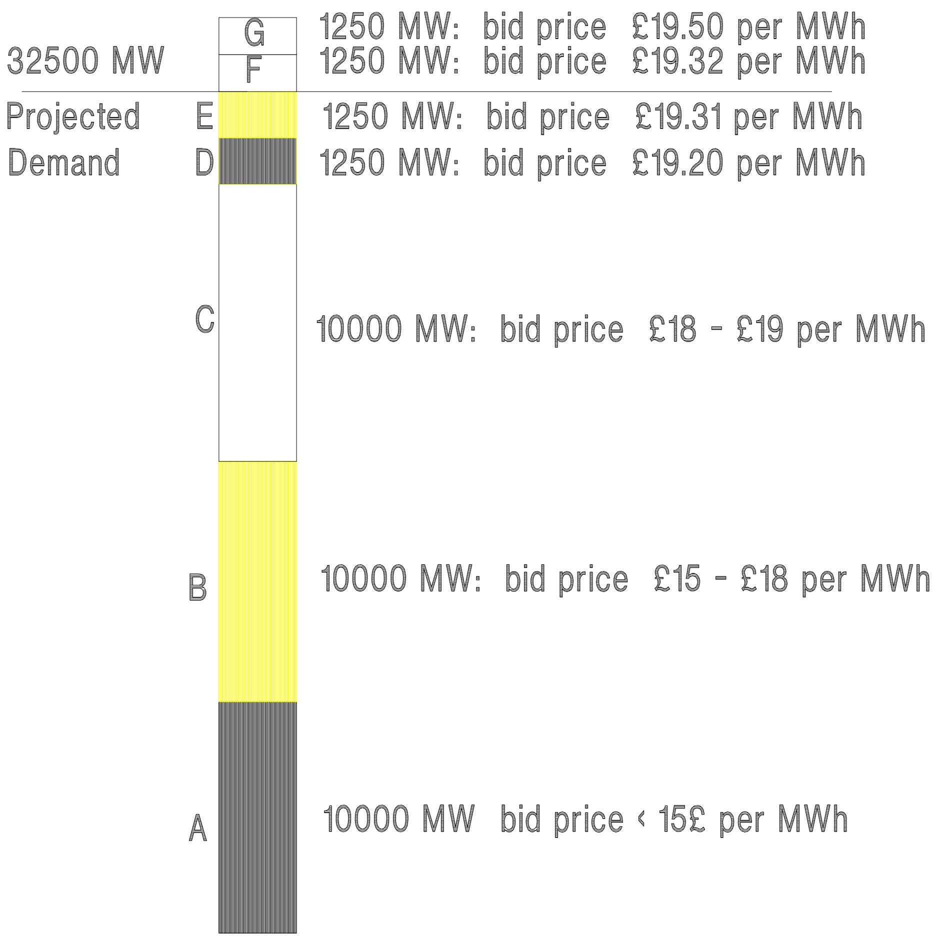


Fig. 4.3 Illustration of the bidding process in the Electricity Pool. The bids were stacked until the required demand level was met. The bid of the highest successful company which bid just below the required demand level set the System Marginal Price (SMP).

The prices which a particular generator bid depended on how long it had been since the generating set last generated if it is not generating in the immediately preceding half hour. This is because it takes energy to warm the unit up as well as more man-power in the run up period. Consequently the bid for those units which have not been generating recently was usually higher than had the plant been operating in the previous half hour.

The highest bid which provided a cumulative generation capacity equal to the projected demand is the **SYSTEM MARGINAL PRICE** (SMP), and all generators who bid below this price were paid at the SMP ***irrespective*** of what their bid was.

An example of the stacked bids is shown in Fig. 7.3

Generators A - E had successful bids and would be all paid £19.31 per MWh.

Generators F and G were unsuccessful.

Illustration of operation of the Pool: Generators A:E are successful but F and G are not. The System Marginal Price is £19.31 per MWh and will be paid for each unit generated by A – E irrespective of the bid they actually made.

There was no reason why a generator should not bid £0 – particularly if it wanted to guarantee a unit ran – i.e. it was kept running and warm to make the bid for the next half hour less. If all generators did that, then the SMP would be £0 and they would have to generate their electricity for nothing!

4.4 The Pool input Price (PIP)

The Pool input price is a combination of the SMP and a capacity charge. This latter is paid to generators who make capacity available irrespective of whether they generate any electricity or not. This capacity may be required to cope with unexpected demands.

PIP = SMP + LOLP*(VOLL - SMP)

LOLP is the loss of load probability. In summer this tended to be very small (e.g. 0.00005) or zero as usually there was plenty of capacity potentially available to deal with changes in demand. In winter it could become important (~0.001) and on some occasions very much higher

VOLL was the value of the loss load and is determined by OFFER and was initially about £2200 per MWh but later revised upwards progressively.

If for example, the SMP was £19.31, the LOLP was 0.00005, and the VOLL was £2200, then

PIP = 19.31 + 0.00005*(2200 - 19.31)
= £19.419/MWh

If LOLP rises to 0.002,

then the PIP will be £23.67 / MWh

The generators got paid the PIP for units that were actually generating, but could receive payment if they were asked to have a generator on standby to cope with emergencies. In this case they were paid:

LOLP*(VOLL-SMP)

4.5 Uplift

The Regional Electricity Companies and Licensed Suppliers purchase electricity at the Pool Output Price (or POP).

POP = PIP + Uplift

- The Uplift was an additional cost which accounted for the fact that it is not always possible to purchase the cheapest electricity because of technical constraints: e.g. the location of generation with respect to demand and number of transmission lines in the area.
- Some stations were **CONSTRAINED ON** irrespective of their bid price as they were critical to security of supply (e.g. Didcot I nearly days).
- Others were **CONSTRAINED OFF** because although they bid below the system marginal price, they are unable to supply because of transmission constraints.
- Stations which were **CONSTRAINED ON** or **CONSTRAINED OFF** were paid for the electectricity the generated (or would have generated) at their respective bid prices.

4.6 Problems with the Pool

The Pool worked fairly well since Privatisation, but both PowerGen and National Power played games with the system and were subsequently fined by the Regulator..

1) In early days, both generators deliberately bid high on stations they knew were likely to be CONSTRAINED ON. In early days these set the SMP and the value artificially. OFFER stepped in and bids from Constrained On stations subsequently are not included in determining the SMP.

2) Both big generators saw that it was to their financial advantage to deliberately make plant temporarily unavailable by additional “Planned” maintenance (or prematurely mothballing plant). As a result the value of LOLP increased, and at one time, the capacity changes amounted to over 20% of total PIP. Because of these practices, OFFER fined both PowerGen and INNOGY nPower requiring them to dispose of 2000MW and 4000MW respectively. These stations were then purchased by Eastern Group on 31st December 1995, who became a third important player in the POOL.

3) The National Grid Company could pass on any charges incurred arising from stations being CONSTRAINED ON or OFF, but there was thus no incentive for the National Grid Company to ensure optimum dispatch of electricity. It was for this reason, that ultimately the POOl was replaced by NETA.

4) The lack of demand side bidding was a weakness with the POOL and it was possible for generators to dictate PIP. Towards the end of the operation of the POOl there was some experimentation with limited demand side bidding.

4.7 Operation of Electricity POOL - Contracts

Generators and Large Customers could enter into ONE- or TWO - way contracts to reduce variations of POOL price which could change considerably over the day and season.

4.7.1 One-Way Contracts

In these contracts there was a **STRIKE** price at which the generator compensated the customer if the **POP** exceeded the **STRIKE** price.

4.7.2 Two-Way Contracts

In a two way contract, there was an upper and lower **STRIKE** price. The generator paid the customer the balance if the **POP** is greater than the upper strike price. Similarly the customer compensates the generator if the **PIP** was less than the lower **STRIKE** price

The reasoning behind such contracts is to make energy charges more predictable

4.7.3 A worked example of the POOL

A full worked example part of which was set as an exercise in a Class in a previous year is shown in Appendix A. As the POOL has now ceased operation, this exercise is for historic interest only.

4.8 Deregulation.-

From Privatisation on 1st April 1990 domestic consumers still had to obtain their electricity from their local REC and the prices of electricity to domestic consumers were regulated according to a formula which determined how the price could change from one year ot the next. This formula which indicated the percentage price change was:

RPI – X + F + E

Where RPI was the Retail Price Index
X was a factor determined by the regulator and initially set at 5.
F was a fossil fuel levy to fund the Non Fossil Fuel Obligation
E was an Efficiency Factor by which utilities could pass on energy efficiency measures to their customers – e.g. promoting the use of low energy light bulbs

This regulation continued until full degregulation of the markets too place in 1998 – 1999.

From Privatisation it was possible for any consumer having a mean demand over 1 MW to purchase electricity could purchase electricity from any REC or indeed any Licensed Supplier. [UEA at the time had a load varying between 1.8 and 3.9MW and potentially could have made use of this, but chose not to initially]. Initially it was though that no company would buy electricity outside their only REC area, but things soon changed when the largest consumer of London Electricity Board, Heathrow Airport decided to purchase its electricity from Yorkshire.

For customers to use suppliers from any location, the customers had to have in place half-hour meters – i.e. meters which could assess demand for each 30 minute period of each day separately. This was because the suppliers would be charged a different price for each half hour period from the eletciricty Pool via the POP.

From 1st April 1994, the threshold was reduced to 100 kW.

From 5th September 1998 [and phased across country until June 1999], all consumers including domestic ones could purchase electricity from any of the above RECs or Licensed Supplier irrespective of locality.

4.9 Implementation of Deregulation

There were several issues that needed addressing before Deregulation could be implemented for domestic consumers. Firstly it had to be recognised that the tariff paid by any consumer actually consists of three components:

1) A charge for the actual units supplied to the customer,
2) A charge for distribution [not transmission] and this will be the same for all suppliers within a given REC area although the charges varied from one REC area to another. In the 1990s, the local REC was the Distributed Network Ooperator and was not allowed to differentiate between companies as to the charges made for this service, i.e. it could not favourably adjust tariffs for supply of its electricity to customers in its area.
3) A charge for Metering Services. Initially this continued to be done by the local REC

To encourage other suppliers and Second Tier RECs (i.e. those from other areas) to get a foothold, the local REC could not reduce its pre-Deregulation prices more than a certain amount for a period of a few years. A a result, new suppliers usually often more attractive tariffs and the local RECs tended to be the most expensive electricity supplier in its own area. Ultimately this restriction on local RECs was removed, but there is still a tendency for supply via the local REC to be among the highest charges.

Interestingly in the months immediately following Deregulation, the cheapest tariffs for electricity within the Norwich area were offered by British Gas whereas the cheapest gas tariffs were offered by Eastern Electricity!

5.4 Payment by Suppliers for Electricity

As indicated above for large consumers, electricity suppliers were charged varying amounts for each half hour period via the POP. As a result they would negotiate more favourable tariffs for those companies who tended to use more electricity when the POP was loswest. This was an issue which had to be addressed when Deregulation was extended to the domestic market as domestic consumers do not have such metering installed.

The supply companies offered a range of tariffs for the domestic market with some companies targettign specific group of consumer. Since the Pool Output Price varied considerably over the day and the supply companies had a single tariff for domeistic consumers (or two tariffs for those on Economy 7), the supply companies would potentially be making a substantial loss at certain periods of the day but a profit at other times. They took the risk of varying demands and prices.

To manage the risk they need to assess the likely profile.

This was done as follows:

- Within a given Distributed Network Operator Area (equivalent to the REC area in the 1990s) the following procedure was used:
- Each supplier would obtain half hourly data from the customers so metered.
  subtract the cumulative total of these customers over the relevant metering period (e.g. three months for billing) – the balance represents the consumption by non-half hour metered consumers customers according to one of 8 or more profiling curves to estimate what each customer has used in any one half hour period. [There were two such profiles for domestic consumers, one for standard tariffs and one for Economy Seven]. These profiles showed a typical distribution of load through a typical day across each half hour period.
- The totals of all the non-half hour consumers estimated in this way was then computed and compared with the net cumulative determined above to derive a correction ratio.
- Attribute electricity take by each supplier according to the number of customers, the relvant profiles and the correction factor.
- This information was then used to calculate the relevant tariffs to be charged over the relevant period based on the indiivudal Pool Output Prices in each hour.

4.11 Regional Variations in Tariffs

For any one electricity supplier, the tariffs charged, though constant across a give REC / DNO area did vary from one area to another. The reasons for this were:

- The overall profile of daily load in the area. Those areas with a high industrial load tended to have a less peaky profile and thus the tariffs would tend to be lower.
- The relative difference in demand over generation in each REC area. Thus in the south the charges tended to be higher as there was a deficit of generation compared to demand.

4.12 Future Developments.

- At the end of the operation of the POOl and its replacement by the New Electricity Trading Arrangements, each of the Regional Electricity Companies, whether still independent or taken over or merged still continue to be the Distributed Network Operator. However, following the introduction of NETA, many of the REC distribution networks were sold to other companies, occasionally as an integral package with the REC, but frequently as separate entities. These new distribution companies are now known as Distributed Network Operators (DNOs). In the region formerly part of Eastern Electricity, the current DNO is Electricité de France while the REC is currently E.oN as the successor to PowerGen.

- Metering all consumers on a half hourly basis could lead to more effective energy conservation and is potentially the way forward so that even domestic consumers would pay different tariffs depending on the time of day they used the electricity. Indeed some utilities in the USA were experimenting with an approach of up tot 5 separate daily tariffs as early as 1990.

5. New Electricity Trading Arrangement (NETA)

5.1 NETA Background

The New Electricity Trading Arrangements came into force in England and Wales on 27th March 2001 and represented a major change in the way electricity was traded. In Scotland the two vertically integrated companies continued to operated as previously.

In July 2002, there were some modifications particularly in terms of the length of time between Gate Closure and the start of real time.

On 1st April 2005, NETA was replaced by the British Electricity Transmission and Trading Arrangements (BETTA), which effectively brought Scotland into the scheme. At this stage there were very limited changes in England and Wales and in effect BETTA is an extension of NETA into Scotland.

There are numerous very lengthy documents on NETA and BETTA on the WEB. One in particular, although a little dated is still a good good and concise summary of how the system works and is accessible from the Energy Home Page and is also included as Appendix B of this handout.

-Overview of New Trading Arrangements V1.0 -

5.2 Main differences compared to the POOL

The critical differences with the POOL are

1. NETA overcomes a major deficiency of the POOL in that the prices were set largely by the generators with little input from suppliers.
2. The majority of purchases/sales of electricity under NETA are done by bilateral contracts between generators and suppliers and do not involved the National Grid. This means that for a particular half-hour period a supplier will contract with a generator to purchase a projected amount of electricity based on expected demands. i.e. this is a form of FUTURES market. Indeed each unit of electricity is traded around seven times on the futures market before it is actuall generated and consumed.
3. The projections are unlikely to be accurate and there will be imbalances arising from changes taking place after the contracts are made e.g.
   - Changes in weather
   - Unforeseen changes in customer demand
   - Breakdowns in the system
   - Etc
4. NETA is concerned primarily in assessing the imbalances which occur at a particular time and provide a mechanism for charging. For instance the demand imposed by customers on the suppliers may increase or decrease above the contract position. The suppliers will then be charged for the imbalance whether it is positive or negative. Clearly, it is in their interest to minimise these imbalance payments and thus they need to predict as accurately as possible what the demand from their customers will be.
5. The role of the National Grid Control will be largely to deal with the imbalances as they arise and ensure that the system remains secure and that collectively over the whole system sufficient electricity is available.
6. NETA favours those generators which can guarantee a specific output in advance. Equally those generators which are flexible in the amount they can output are favoured, i.e. they can change demand fairly quickly as required to balance supply. Equally if suppliers have customers who can load shed, then these suppliers will be at an advantage and could pass on more favorubale tariffs to their customers. The Magnox Nuclear stations are very inflexible and will not be able to provide balancing mechanism services which can be charged at a premium. Equally, CHP and Renewable generators are at a disadvantage, particularly Wind generators as their supply is unpredictable. It is partly for this reason that the Renewable Obligation was introduced – although not until 12 months after the introduction of NETA. CHP does not have the alternative benefit of renewable generation and is at a disadvantage compared to the POOL as small scale CHP normally operates on a heat demand led mode and the electrical output this varies
7. The main basis of NETA is the Balancing Mechanism (BM) unit. For a generator a BM unit will normally be a single physical generating set (> 50MW) or a collection of smaller sets. Many power station have several sets but these are usually separate BM units. For a supplier the BM unit is likely to be a single large consumer or a collection of consumers. A typical size for a BM Unit (either generator or supplier) is about 50 MW or about 0.1% of peak demand.

5.3 An brief Overview of NETA – Physical Notifications

Most electricity trades will be direct contracts between generators and suppliers, although there may also be Electricity Traders operating to broker deals between the generators and suppliers.

Each supplier and generator will have to project their supply or demand requirements in advance for each 30 minute period of each day. These must be done in two stages.

1. An Initial Physical Notification (IPN) of the electricity to be traded by 11:00 am on the day preceding the day in which the half hour period occurs.
2. A Final Physical Notification (FPN) which is made by 3.5 hours prior to the real time. For instance if the half hour period is 17:00 – 17:30, then FPN must be made by 13:30. The time of 13:30 is known as GATE CLOSURE. From mid July 2002 the time of gate closure was reduced from 3.5 hours to 1 hour before real time. Thus GATE CLOSURE now at 12:00 noon refers to the real time period 13:00 – 13:30.

Obviously between IPN and FPN, adjustments are likely to be made on the contracted supply as more refined information on changing weather and other physical factors (e.g. sudden plant breakdown) becomes available. These are traded on the Short Term Market, and details of the prices paid in each half hour period are published on the ELEXON Web Site about 14 days after the day in question under the heading “Market Index Data” or MID.

Once Gate Closure has been reached, the contracts are fixed and represent the quantities of electricity which each party will be obliged to supply or generate for the given period. Financial Transactions will take place just between the parties concerned.

Both the IPN and FPN may be at a constant level, but in many cases, particularly for demand side BM units, the projected demand may vary over the half hour period. Thus BM units may define a single IPN/FPN for the whole half hour period, or on a minute by minute basis. For example, from 08:30 to 09:30, the demand on many demand BM units will increase quite rapidly as work starts for the day, and recognition of this can be included in the Physical Notifications for the two half hour periods 08:30 – 09:00 and 09:00 – 09:30.

No change in the contract position is possible after GATE CLOSURE irrespective of any changes which may occur such as changes in demand or breakdown of generating plant. To maintain system stability any trade enters the Balancing Mechanism Period and it is here that NETA fully comes into force. It is concerned about charging for electricity generated or not generated which is above / below the contract position. Equally, any difference in the supply above/below the contract position will be charged..

Since the contract position is the basis for charging if any deviations occur, it is for this reason that the amounts contracted are notified to the System Operator or National Grid Company in the Physical Notifications. It should be noted that though the volume of electricity contracted must be notified to the System Operator, the actual contract price is a matter for the contracting parties only.

One reason for the two different Physical Notifications is to allow the National Grid Company (NGC) responsible for system security to check that the contract provide a secure system. Thus if all the contracted generators were in the north and the majority of the supply was in the south, then there would be system constraints which would affect the secure operation. In this way the NGC can call on generators specifically for security operation and/or provide cover for emergencies. Such generators (or even load shedding suppliers) will be paid for these balancing mechanism services, but these represent an additional complication of NETA which will not be covered in this course. One unit at Ironbridge Power Station was deliberately run under low load so that it was flexible to ramp up or down at short notice and thereby provide balancing mechanism flexibility during real time operation. Such services carry a premium prices and can be attractive or some operators. Thus the pumped storage schemes are almost solely used for BM balancing mechanism duty and each MW so generated can command a very high price.

5.4 NETA: The Balancing Mechanism

As electricity demand is transient there will always be discrepancies between the projections made by Gate Closure and the actual electricity generated or supplied at the real time. The Balancing Mechanism provides a means whereby the NGC can ensure sufficient supply and demand.

All BM Units (whether generators or suppliers) may in addition to their statutory requirement to notify their contracted supply/demand make an OFFER or BID to change their contractual position after GATE CLOSURE. This OFFER or BID would be between the bM Unit and The System Operator.

For a generating BM unit an **OFFER** would imply an offer to INCREASE generation, whereas from a supplying BM unit, an **OFFER** would represent an offer to REDUCE demand (probably through Load Shedding) - see Fig 5.1. Though the projected demand is specified on each half hour period, it is quite probable that the forecast demand might change during that period as is also shown.

A ***BID*** will be to reduce the output of a ***BM*** generating unit or increase the demand of a supplying unit.

The purpose of these ***OFFERS*** and ***BIDS*** is to permit flexibility to cope with the actual demand at the real time rather than the projected generation and demand as given at ***GATE CLOSURE.***

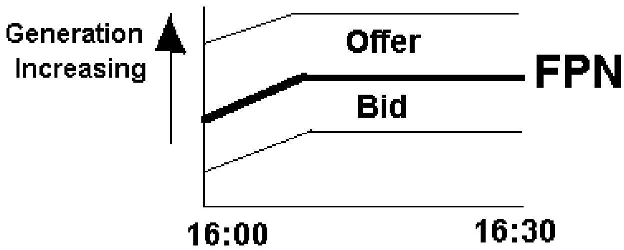


Fig. 5.1a The FPN is shown to increase and then remain steady. The diagram shows that generators can OFFER to increase their output (at an OFFER Price). Equally, they may BID to lower their output. Note that OFFERS for generators increase output, BIDS decrease output. Also the convention that the increase is **+ve.**

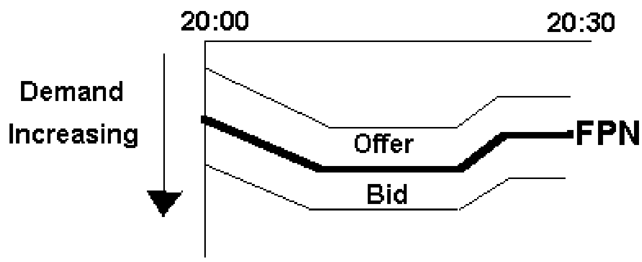


Fig. 5.1b Showing a varying FPN during a 30 minute period. This diagram is for Suppliers. Once again, there is an OFFER and a BID. However, an OFFER will reduce demand and a BID will increase Demand. Thus increasing demand is plotted **-ve.** This +ve and –ve convention allows both generator and supplier information to be plotted on same diagram.

The OFFER and BID prices from a particular BM unit will depend on the ability of the BM unit to respond and also the price the generator or supplier is prepared to see the BM unit deviate from the contractual position. Thus to increase demand will require additional fuel in a fossil fuelled station and this will tend to be reflected in the OFFER price. The OFFER price (i.e. the price the BM Unit is willing to be paid) to increase the FPN (increased generation for generators or reduced consumption for suppliers) and will in general not be the same as the BID price.

At first site it may appear odd that a Supplier could reduce demand. In fact many large customers have Load Shedding arrangements which means that at relatively short notice these customers are prepared to reduce their demand by a given amount, and in doing so get a preferential price for all the electricity they consume. The ***OFFER*** price for a supply ***BM*** unit [i.e. the Price that is paid by the System Operator to the Supply BM unit] thus reflects the discount the supplier has to pay to the Load Shedding Consumer.

NOTE: An OFFER (whether from a generating BM Unit or a Supplying BM unit) will always increase the (final Physical Notification Level) FPN level. In the case of the supply, this in effect means reducing the demand (or making the demand less –ve). It is for this reason that the two types of BM unit have opposite signs. Conversely a BID will reduce the FPN level for both generation and supply.

In many cases, a BM unit may have differential OFFER and / or BID prices depending on how much the FPN is to be raised. Thus to raise the FPN by say 50 MWh over the 30 minute period might be offered at say £30, but to raise the FPN by a further 50 MWh to 100 MWh would be offered at say £40.

This procedure is indicated in Fig. 5.2. The FPN is at 50 MW. The offer price to increase the output between the FPN and 100 MW would be £20 per MWh, but to increase to between 100 and 200, the offer would be £30 / MWh..

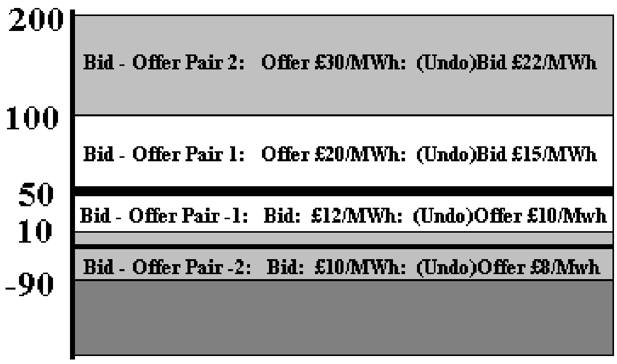


Fig. 5.2 Illustration of multiple bids for different ranges. Also included in this diagram are the Undo Offers and bids.

Two points to note:-

1) The Physical Notifications only require the volume of the generation/demand in the relevant contract.
2) The Bids and Offers must also include not only the volume of electricity but also the cost.

NOTE: The physical notification refers to the rate of production/ consumption of electricity, whereas the prices are in terms of a physical total quantity. Do remember though that we are dealing with 30 minute periods, so if a unit was assigned an FPN of 50 MW and was subsequently called upon to run at 50 MW above the FPN – i.e. at 100MW for the whole 30 minute period, it would generate

(100 – 50) * 0.5 MWh = 25 MWh as balancing mechanism duty and also 50 * 05 = 25 MWh as contract [the 0.5 in each case refers to the half hour period]..

The decision to operate at anything other than the FPN is taken by the National Grid Company who will require a company offering or bidding to make good on their offer or bid if the system becomes out of balance after Gate Closure. Obviously the NGC will normally take up those offers and bids which are cheapest.

However:

1. System constraints may dictate that higher priced offers/bids are taken up (this is a little akin to the constrained ON/ constrained OFF situation in the POOL).
2. If a BM Unit fails to deliver on its offer/bid, the NGC for whatever reason, then the NGC will have to take an alternative which will almost certainly be higher and the defaulting BM unit will be penalised accordingly such that neither the NGC nor the supplier (and ultimately the consumer) is affected in terms of price.

The balancing mechanism begins immediately on Gate Closure and continues throughout the period until the end of the real time half-hour. Simultaneously, there will be balancing occurring for the following half-hour periods. Electricity supply is a very dynamic operation and supply and demand is continually changing, and hence many bids/offers may be taken up.

Once a **BM** unit and the **NGC** agree on the **ACCEPTANCE** of an **OFFER** or **BID**, this is then binding on both parties (see above for situation with defaulting BM units).

However,

The NGC cannot cancel an **ACCEPTANCE** of **BID/OFFER** once it has been made. This means that a problem would occur, if after accepting an offer for more electricity, the demand suddenly falls. To overcome this there are UNDO options – i.e. an **UNDO BID** will remove an **OFFER** and conversely an **UNDO OFFER** will remove the effects of a previous **BID.** Since this will incur costs on the **BM** unit (e.g. a generating unit may have kept on staff to start up a new unit only to have to stand down), the **UNDO BIDS** and **UNDO OFFERS** will be less than the corresponding normal **OFEERS** and **BIDS** as shown in Fig. 5.2. This means that the NGC picks up the cost for calling on a Bid/Offer only to cancel it later.

The **OFFERS** and associated **UNDO BIDs** are normally linked as a pair as shown in Fig. 5.2. These are numbered successively +1, +2, +3 on the normall **OFFER** side (i.e. increase generation/decrease consumption) and –1, -2, -3 on the normall **BID** side.

5.5 Example of the Balancing Mechanism in operation

Fig. 5.3 shows a period of 30 minutes with a given Final Phsycial Notification for a given BM generating unit. Because of demand changes at B the demand is now forecast to rise to E then remain stable before falling to K, remaining stable to L and the returning to the FPN at the end of the period. For this example it is assumed that the fPN level is 50 MW. Table 5.1 shows the Bid – Offer Acceptances that have been agreed between the generator and the National Grid Company.

Table 5.1. Bid – Offer Acceptances for period

Bid/Offer Pair	**OFFER (£/MWh)**	**BID (£/MWh)**	**Range (MW)**
+3	**50**	**35***	**200 to 400**
+2	**30**	**25***	**100 to 200**
+1	**15**	**13***	**50 to 100**
-1	**13***	**12**	**10 to 50**
-2	**11***	**10**	**-90 to 10**

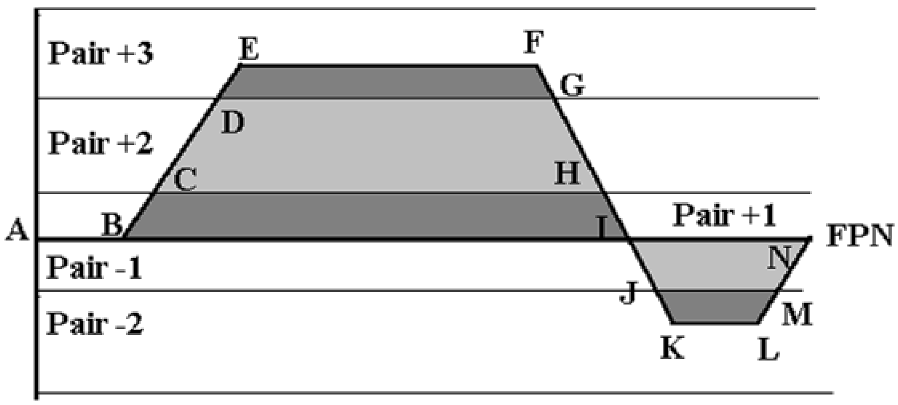


Fig. 5.3 An example of Offers and Bids in a single half hour. Offers are accepted for the first part of the period which sees the level rise above FPN into the region covered by Pair +3. Later in the half hour, BIDS are accepted to reduce the FPN into the region covered by Pair –2. Typical prices of OFFERS/ BIDS are shown in Table 5.1 above.

The *items in Table 5.1 are not invoked in this example as all OFFERS and BIDS are accepted and then not changed at this stage.

The relevant Pair in operation are as follows:-

	OFFER/BID No.
A – B	At FPN no BOA required
B - C	Pair +1
C - D	Pair +2
D – E – F - G	Pair +3
G - H	Pair +2
H – I	Pair +1
I – J	Pair –1
J – K – L – M	Pair -2
M - N	Pair -1

Now suppose that the demand level changes after acceptance of the OFFERS and BIDS to that shown in Fig. 5.4. i.e before reaching D, the level plateaus at P and is now predicted to continue at this level until Q when it will then fall back to the FPN. As a result of these changes the UNDO BIDs (part of Pair +2 and all of PAIR +3) will be invoked, while new OFFERs and UNDO OFFERS will be required towards the end of the period. .

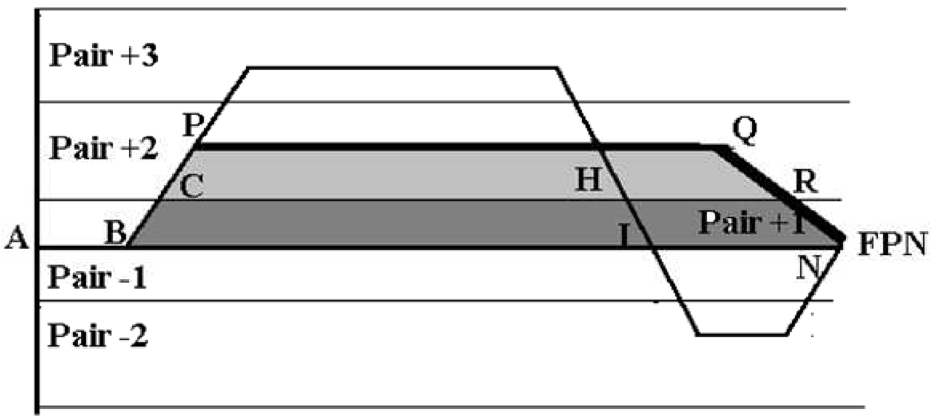


Fig. 5.4 showing revised actual level relative to FPN - A – B – C – P – Q – R – N.

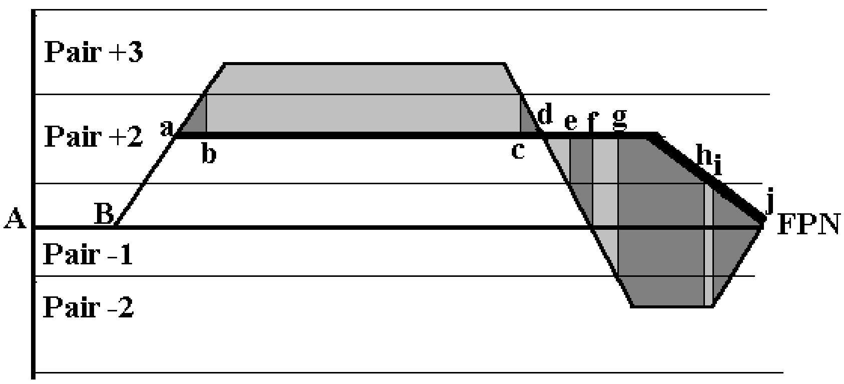


Fig. 5.5 Periods when initial Offers/Bids have had to be cancelled (compare with Fig. 5.3 and 5.4).

Actual Adjustments needed

- Between a and b, part of the original **OFFER** in Pair +2 (i.e. at £30/Mwh) is "cancelled" by the **UNDO BID** at a price of £25/MWh – that means the BM unit benefits by £5/MWh).
- From b – c the original **OFFER** in Pair +3 is "cancelled" entirely by the **UNDO BID** and also part of the original **OFFER** in Pair +2 is also "cancelled").
- The situation for c – d is similar to a – b, while d – e would represent an additional **OFFER** in Pair +2.
- From e – f the addition would be the **OFFER** price for both Pair +1 up to its limit and the remainder from Pair +2. These are new and first time offers above the original level so there is no **UNDO** situation here.
- From f-g there is the **UNDO OFFER** of Pair –1 + the new **OFFER** of Pair +1 and Pair +2.
- For g – h there is the full **UNDO OFFER** for Pair –1, a part **UNDO OFFER** for Pair – 2, a new **OFFER** for Pair +1 and part new **OFFER** for Pair +2
- For h – i, there are the **UNDO OFFERS** for Pair-1 and Pair –2 (part), and also a full new **OFFER** for Pair +1
- Finally for i – j there will be **UNDO OFFERS** covering the whole range of Pair –1 and part Pair –2 and a new **OFFER** for Pair +1.

As electricity demand and supply are changing dynamically, it is expected that there may well be several changes in requirements for bids/offers or undo offers/bids. Clearly in calculating what is to be paid to, or charged from, a BM unit depends on all proceeding BID/OFFER Acceptances.

5.6 NETA Concluding Remarks

- While the above gives an overview of NETA, the actual mechanisms also have to take note of the dynamic characteristics of each BM Unit. For instance a generating set takes some time to respond to instructions to change its output. An example is a 500 MW unit which if it is fully warm will take up to 90 minutes to synchronise and a further 90 minutes to load up to maximum load.
- Some generating units e.g. Magnox stations, cannot come back on load in less than a minimum time (usually around 24 – 48 hours once their load has been reduced.
- Some demand BM units can be changed almost instantaneously by load management. But in these cases, a finite warning of a pre-determined period (e.g. 1 hour) is needed.
- The National Grid Company cannot accept unlimited power from one part of the country because of transmission constraints.
- All the above must be considered by NGC when accepting any particular BID or OFFER. In some cases, they may not be able to accept electricity at the best price. In the past this has been referred to as NON-OPTIMAL DESPATCH (NOD).

5.7 Implications of NETA on Renewable and CHP Generation

The New Electricity Trading Arrangements have had a significant effect on both the generation of electricity by renewables and also CHP. In the first year, the effects were generally negative, but this has been overcome with the introduction of the Renewable Obligation which largely compensates renewable generators, but serious issues still remain with small scale CHP Units. There is no equivalent of a **"Heat Obligation".** Some of the renewable generators – e.g. the few large Hydro can accurately predict their output and can cope with the requirements. On the other hand wind generation is very variable and imbalance charges partly reduce the benefits of the Renewables Obligation.

Many small scale CHP generation schemes and much of smaller renewable generation are what is known as embedded schemes. That means they are connected to the local distributors network and not the National Transmission Grid. Under the POOL, these found favour with the local distributors as they did not incur the transmission losses, and thus the schemes (e.g. UEA) were able to be paid at a price which was above Pool Input Price to allow for the reduced charges the local distributor would have to pay for the "embedded" electricity.

This allowed a degree of predication on behalf of CHP operators as their contract was likely to be based as the Pool Input Price plus a proportion of the savings on the transmission. With NETA, since small scale CHP are normally run heat-demand led, this means that the electricity output is variable and can affect the imbalance load of the Electricity Supplier to whom surplus output is sold. As a result, and knowning that they (i.e. the Supplier) will be charge for imbalance, the tariffs the Supplier is now prepared to offer such embedded generation tends to be noticeably less favourable than during the POOl era. Consequently after several years of growth in small scale CHP deployment there were several years of stagnations following the introduction of NETA.

It is true that the majority of the electricity generated by small scale CHP is consumed on the premises, and that over a 24 hour period schemes such as UEA are net importers of electricity. Nevertheless NETA is making operation of CHP more difficult to predict as the income from sales of excess has fallen..

5.8 Implementation of BETTA

The British Electricity Trading and Transmission Arrangements (BETTA) came into force on 1st April 2005. There was little impact in England and Wales, but there were major changes in Scotland as the two former vertically integrated companies were no longer responsibl;e for transmission and were integrated into NETA.

Several issues needed addressing before the system could be implemented GB wide: these included:

Changing way in which Interconnectors between England and Wales and Scotland were operated. Prior to April 1st 2005, Scotland was , in effect, treated in the same way as France.

The definition of Transmission as opposed to Distribution needed to be resolved as these were different in Scotland.

i. In England and Wales, all electricity transmitted as voltages higher than 275 kW was deemed to be Transmission and the responsibility of the National Grid Company. Electricty distributed at lower voltages – i.e. 132kV, 66kV, 3kV, and 11kV was deemd to be Distribution and the responsibility of the Distributed Network Operator (DNO).

ii. In Scotland the differentiation for transmission was voltages 132kV and above.

From the implementation of BETTA, there were three transmission Network Licences:

i). National Grid Transmission License (NGTL) covering England and Wales
ii). Scottish Power Transmission License (SPTL) covering the South of Scotland
iii). Scottish Hydro Electric Transmission License (SHETL) covering the North of Scotland

A map showing distribution of 132kV, 275kV, and 400 kV transmission liens in show in Fig. 5.6

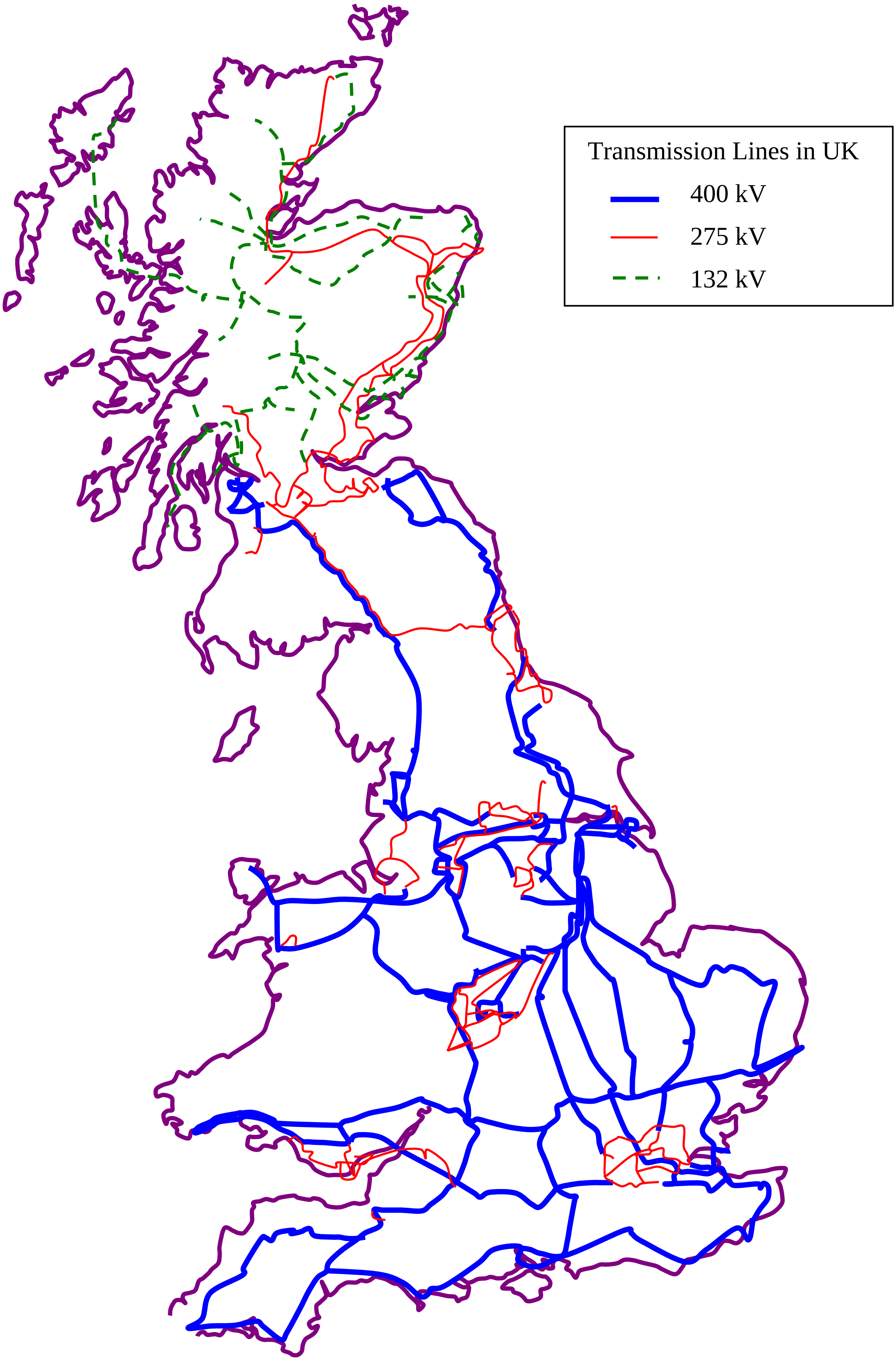
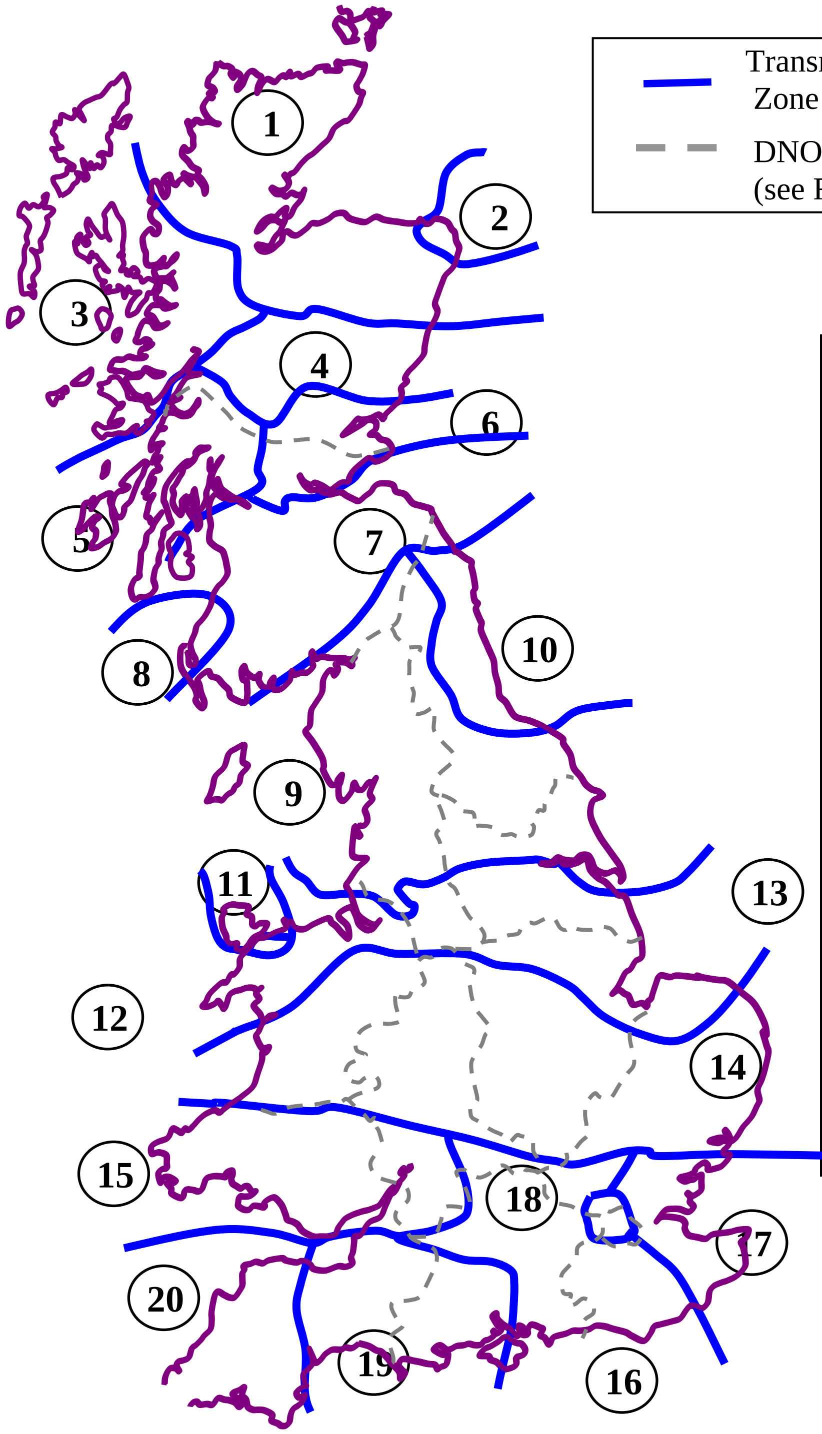


Fig. 5.6 Transmission lines in England, Wales and Scoitland

The National Grid Company became the GB System Operator (GBSO) covering all areas. However, the GBSO was regulated to ensure that those functions under NGTL did not conflict with the SO requirements for system stability or to predujice issue relating to SPTL or SHETL.

Prior to the inditroduction of BETTA, little attempt had been made to address differential charges for transmission across Great Britain. However, this became more important with the inclusion of Scotland into NETA, and connection charges are now made by the National Grid Company for connecting generators to the Transmission Network according to 21 different zones as shown in Fig. 5.7.



GENERATION: ZONE Charges

Zone No.	Zone Name	Zonal Tariff (£/kW)
1	North Scotland	£21.59
2	Peterhead	£19.23
3	Western Highland & Skye	£19.86
4	Central Highlands	£16.44
5	Argyll	£14.68
6	Stirlingshire	£14.03
7	South Scotland	£13.02
8	Auchencrosh	£10.14
9	Humber, Lancashire & SW Scotland	£5.88
10	North East England	£9.25
11	Anglesey	£6.41
12	Dinorwig	£9.28
13	South Yorks & North Wales	£4.00
14	Midlands	£1.97
15	South Wales & Gloucester	-£2.46
16	Central London	-£5.71
17	South East	-£0.91
18	Oxon & South Coast	-£0.27
19	Wessex	-£4.10
20	Peninsula	-£8.57

Table 5.3. Transmission Zone charges

Fig. 5.7 Different Transmission Zonal Charging Regions. Note the zones shoiwn here are a little different from those used originally in 2005..

The above charges are for generators connecting to the transmission network and it is noticeable that in the southwest, generators will be paid to connect. Unfortunately the charges for connection are the highest in the north of Scotland where the greatest potential for renewable generation is. On the demand side a separate system of charging is inplace based on the the REC Zone areas as delineated in Fig. 3.1 – i.e. based on original REC names. This information is shown in Table 5.4

Zone Name.	Demand Tariff (£/kW)	Energy Cosnumption Tariff (p/kWh)
Northern Scotland	£1.45	0.18
Southern Scotland	£6.36	0.83
Northern	£9.88	1.29
North West	£13.65	1.73
Yorkshire	£13.62	1.75
N Wales & Mersey	£14.08	1.81
East Midlands	£16.37	2.13
Midlands	£17.81	2.30
Eastern	£17.06	2.24
South Wales	£21.54	2.71
South East	£20.08	2.59
London	£22.16	2.71
Southern	£21.10	2.74
South Western	£23.55	3.00

Table 5.4 Transmission Charges for Demand Areas as delineated in Fig. 3.1. Note these are ordered in the reverse way from the generating tariff. – i.e. charges are hishest in South West and lowest in north of Scotland. The first colum gives information for large consumers measured on half-hour meters, the final column is the amount of the unit charge attributable to transmission in each region.

5.9 Changes in ownership of RECs and also DNOs

At the time of privatisation all the original RECs continued as privatised entities. However, progressively all the RECs saw significant changes in ownership. The following table shows the current (2008) ownership of the respective areas and also the DNO areas.

Zone Name.	Local REC	DNO
Northern Scotland	Scottish and Southern (British)	
Southern Scotland	Scottish Power / Iberdrola (Spanish)	
Northern	nPower - German	CE Electric
North West	E.oN - German	United Utilities
Yorkshire	nPower - German	CE Electric
N Wales & Mersey	Scottish Power / Iberdrola (Spanish)	
East Midlands	E.oN- German	Central Networks (E.ON) - German
Midlands	nPowe -German	
Eastern	E.oN - German	EdF
South Wales	Scottish Power / Iberdrola (Spanish)	Western Power
South East	Electricité de France	
London	Electricité de France	
Southern	Scottish and Southern (British)	
South Western	EdF	Western Power

Table 5.5 Current Ownership of RECs and DNOs

5.10 A review of the impact of NETA

Aparts from the impact on Renewables and CHP as discussed in section 5.7. There have been several other consequences of the introduction of NETA.

Over the first 12 – 15 months of operation, the wholes sale price fell from an average of around £20 per MWh to around £14 per MWh (Fig. 5.8).

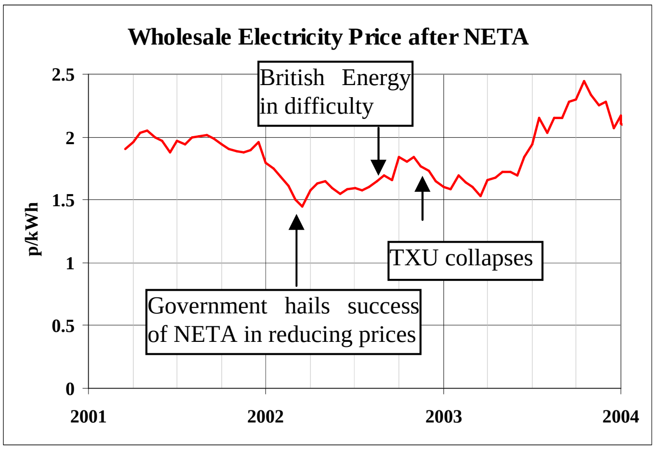


Fig. 5.8 Variation of wholesale prices in first few years after introduction of NETA.

The Government hiled the success of NETA in bringing down prices around April 2002. However, this was achieved by closing or mothballing many plant which did not bode well for the long term future.

In September 2002, British Energy got into difficulty when the price was just 1.4p per kWh and was bailed out with a loan from Government (subsequently repaid). In November 2002, TXU who owned Eastern Electricity and three power stations collapsed.

Those companies which only had a generation port-folio were particularly vulnerable. TXU was vulnerable because the thee coal fired power stations it owned were coal fired and among the least efficicient of all stations.

Subseuqently the prices rose, then fell sharply folloing the opening of the Balzand and Langeland gas pipe lines, but price have risen significantly again in last 12 months. (Fig. 5.9.

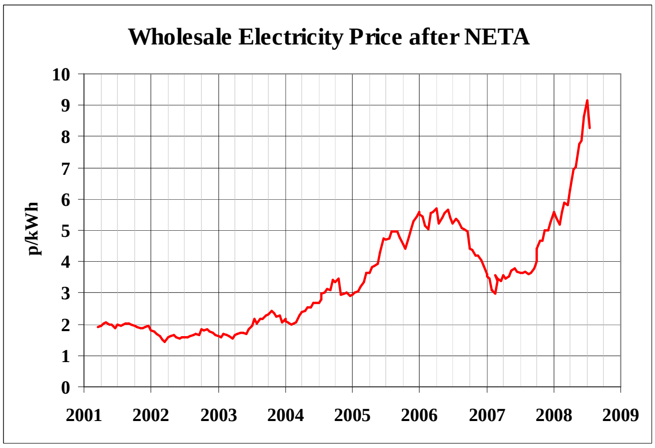


Fig. 5.9 Variation in wholesale price of electricity since introduction of NETA.

Appendix A. AN EXAMPLE OF THE OPERATION OF THE ELECTRICITY POOL

NOTE: This worked example is mostly for historic interest only in the UK but some countries are still operating a derivative of this system. This example has previously been used as a practical exercise in Classes.

You are a manager of Electric Power plc which operates 6 power stations, A, B, C, D, E, and F. For station A, you have a one-way contract with a customer with a strike price of £22.00 per MWh. For station B, you have a two way contract with upper and lower strike prices of £21.50 and £21.20 per MWh respectively.

You are informed by the National Grid Company that the predicted demand for the 30 minute period (1700 - 1730) the following day is 42 500 MW. The loss of load probability is 0.0005 while the value of lost load is £2400 per MW.

Your bid prices for the six stations to supply electricity to the Pool are shown in Table 2. Following the bidding you are informed that full power will be required from stations A, B, C, and D, and that station E will be required on standby. Table 3 shows the bid prices from other generators.

NOTE: In the information provided the column labelled Rank was not completed. This ranking was the first think that needed to be evaluated.

What are the pool input and output prices for the half hour period, and what will be the income for your company during that period? Clearly state any assumptions you make.

[You may neglect transmission losses and assume that the ***UPLIFT*** arises solely from additional capacity charges and sub-optimal scheduling and despatch by the National Grid Company].

TABLE 2. POOL BID PRICES BY ELECTRIC POWER plc

Station	Capacity (MW)	bid price (£/MWh)	Rank
A	470	10.00	1
B	530	10.00	1
C	420	19.68	14
D	370	20.02	20
E	470	19.82	18
F	270	19.23	10

TABLE 3. BID PRICES FROM OTHER COMPANIES

Company	Capacity (MW)	bid price (£/MWh)	Rank
1	11500	10.00	1
2	10500	15.00	4
3	7500	17.00	5
4	1500	20.09	22
5	180	20.03	
6	530	19.84	
7	300	18.00	
8	3600	17.50	
9	1800	18.37	
10	1600	17.91	
11	900	19.55	
12	900	19.81	17
13	850	19.60	13
14	450	19.72	15
15	1100	19.51	11
16	320	19.73	16

None of the stations in Table 3 are either constrained on or off. Company 6 has been informed that it will not be required as standby.

Solution

Station F is not being asked to generate but Station D is which has a higher bid, Station F must be "**constrained off**", so neglect this station temporarily when constructing merit order table.

The maximum bid price which matches predicted demand of 42500 is £19.81 which is the System Marginal Price. The company matching this price is company 12, but for this company the generator will be running under low load (i.e. 660 MW of the potential 900 MW). However, Electric Power D is **constrained on** so the actual generation required from company 12 is only 660 - 370 (i.e. 290 MW). Thus the balance of 610 MW and the 470 MW requested standby of Electric Power E are the standby capacity (since company 6 was not requested for capacity standby and neither company 5 or 4 were **constrained on**).

Now rank all the stations as in the table 4 below and work out the cumulative generation capability.

The maximum bid price which matches predicted demand of 42500 is £19.81 which is the System Marginal Price. The company matching this price is company 12, but for this company the generator will be running under low load (i.e. 660 MW of the potential 900 MW). However, Electric Power D is **constrained on** so the actual generation required from company 12 is only 660 - 370 (i.e. 290 MW). Thus the balance of 610 MW and the 470 MW requested standby of Electric Power E are the standby capacity (since company 6 was not requested for capacity standby and neither company 5 or 4 were **constrained on**).

The Pool input Price (PIP)

$$= \text{SMP} + (\text{VOLL} - \text{SMP})*\text{LOLP}$$
$$= £19.81 + (2400 - 19.81)*0.0005$$
$$\mathbf{= £21.00 / MWh}$$

================

The additional capacity charges refer to the 610+470 MW noted above i.e. 1080 MW

The charge for the **constrained off** and **constrained on** stations refer only to their bid prices

So total output price for all units generated will be (remembering for half an hour!!! Incorporated as the factor ***2*** in equations)

$$(42500-370)*\text{SMP}/\mathbf{2} + \underbrace{370*20.02/2}_{\text{constrained on bid price}}$$

$$+ \underbrace{270*19.23/\mathbf{2}}_{\text{constrained off bid}} + \underbrace{(42500-370+1080)*2400*0.0005/\mathbf{2}}_{\text{capacity payment}}$$

The factor 2 refers to half an hour

Total cost =
£417297.65 + 6299.75 + 25926 = £449523.4

Total units generated = 42500/***2*** = 21250 MWh

so Pool output Price

(**POP**) = 449523.4/21250 = £21.15 per MWh

or uplift = £0.15 per MWh

Since the **POP** is less than £22.00 there will be no payment by Electric Power to its customer for the one way contract. However, since the **PIP** is less than the lower strike price, Electric Power will be paid the difference (i.e. £21.20 - £21.00 = £0.20) for every unit generated by the two-way contract partner.

So income for electric power in half hour period will be:-

Stations A, B, and C at **PIP**

i.e. (470 +530 + 420)*21.00/2 = £14910.00

Station B supplementary payment from contract

(530*0.20)/2 = 53.00

Capacity payment for station E

= 470*2400*0.0005/2 = 282.000

Constrained off payment for station F

270*19.23/2 = 2596.05

Constrained on payment for stations D

370* 20.02/2 = 3703.70

TOTAL income = **£21544.75**
========

TABLE 4. Calculation of Summulative Capacity

Company	Capacity (MW)	bid price (£/MWh)	Rank	Cumulative Capacity (MW)
Electric Power A	470	10.00	1	470
Electric Power B	530	10.00	1	1000
1	11500	10.00	1	12500
2	10500	15.00	4	23000
3	7500	17.00	5	30500
8	3600	17.50	6	34100
10	1600	17.91	7	35700
7	300	18.00	8	36000
9	1800	18.37	9	37800
Electric Power F	270 cons-trained off	19.23	10	
15	1100	19.51	11	38900
11	900	19.55	12	39800
13	850	19.60	13	40650
Electric Power C	420	19.68	14	41070
14	450	19.72	15	
16	320	19.73	16	
12	900	19.81	17	
Electric Power E	470	19.82	18	
6	530	19.84	19	
Electric Power D	370	20.02	20	
5	180	20.03	21	
4	1500	20.09	22	

Appendix B.

Original Ofgem Document relating to introduction of NETA

ofgem

dti

Department of Trade and Industry

31 May 2000

An Overview of the New Electricity Trading Arrangements V1.0

A high-level explanation of the New Electricity Trading Arrangements (NETA)

Reformmated from original for NBS-M009

1. INTRODUCTION

This document provides a relatively high-level explanation of the New Electricity Trading Arrangements (NETA). It should be read in conjunction with a number of other explanatory documents that have been or will be produced by the NETA Programme.

The audience for this document is expected to include those who are not familiar with the existing electricity trading arrangements in England and Wales. This document does not, therefore, explain how the New Electricity Trading Arrangements change from those currently in place. Furthermore this document is aimed at providing a factual description of how the New Electricity Trading Arrangements will operate, rather than attempting to explain why they will operate in a particular manner. Given the intended audience, an attempt has been made to avoid using existing and new Industry jargon and acronyms, however some basic understanding of the major processes involved in the electricity supply chain (i.e. generation, transmission, distribution, and supply) and markets in general is assumed.

2. BASIC PRINCIPLES

One of the basic principles of the New Electricity Trading Arrangements is that those wishing to buy and sell electricity should be able to enter into any freely negotiated contracts to do so. It is expected that under the new trading arrangements, bulk electricity will be traded on one or more exchanges and through a variety of bilateral and multilateral contracts. Those buying and selling electricity on exchanges and through bilateral contracts are likely to include not only generators and suppliers (who produce or consume physical quantities of electrical energy), but non-physical traders as well.

The role of the NETA Programme is not to dictate how energy will be bought and sold on these exchanges or in bilateral contracts. Instead it is to provide mechanisms for near real-time clearing and settlement of the imbalances between contractual and physical positions of those buying, selling, producing and consuming electrical energy. In practice, traders of electricity may buy more or less energy than they have sold; generators may physically generate more or less than they have sold; and the customers of suppliers may consume more or less energy that their supplier has purchased on their behalf. The central NETA systems are designed to measure these surpluses and deficits (or *imbalance*s) and to determine the prices at which they are to be settled in order to send out invoices and payments for them.

The processes involved in calculating and settling these imbalance volumes is referred to as 'Imbalance Settlement'. It should be reiterated that the purpose of Imbalance Settlement is not to price and settle bulk purchases and sales of electrical energy. Instead it is to price and settle the surpluses and deficits arising from the smaller differences between the contractual and physical positions of market participants.

The process of Imbalance Settlement requires a comparison of the quantities of electrical energy that parties have purchased and sold under contract with their metered quantities of physical generation and demand. This comparison is needed in order to determine an imbalance volume (i.e. a surplus or a deficit). It is also necessary to determine a set of prices for settling the surpluses and deficits. Because metered data for generation and wholesale demand is available on a half-hourly basis (i.e. electricity meters in England and Wales are set up so that the kWh of energy generated or consumed by generators or suppliers is measured on a half-hourly integrated basis), Imbalance Settlement will also operate half-hourly under.4 NETA. Thus imbalance volumes and imbalance prices will all be calculated on a half-hourly basis, and settled on a daily basis, approximately 28 days in arrears.

In addition to Imbalance Settlement, the central elements of the new trading arrangements are designed to fulfil a second related role. This second role is to provide a mechanism for adjusting the intended operating levels of generation and demand in real time.

The requirement to provide this mechanism is twofold. First, it is likely that the aggregate level of generation that generators intend to (and/or actually) produce will not match the aggregate level of demand that customers of suppliers intend to (and/or actually) take at any given time. Second, for a number of detailed technical reasons (including the fact that the transmission network in England and Wales has only a finite capacity), it is sometimes necessary to be able to adjust the level of production or consumption of individual generators or demands away from the level at which the generator or customer would otherwise wish to operate. By adjusting the output or inputs of generators and demands in this way, localised overloading of the transmission system can be prevented.

In addition to Imbalance Settlement, the NETA arrangements therefore provide for the creation of a 'Balancing Mechanism'. As discussed above, the Balancing Mechanism provides a means of adjusting the level of production or consumption of individual generators or demands. Under NETA, the 'System Operator' will determine what actions need to be taken in the Balancing Mechanism in order to maintain the required national and local balances of generation and consumption.

3. THE BALANCING AND SETTLEMENT CODE (BSC)

The central elements of the new trading arrangements provide for two basic functions: the Balancing Mechanism and Imbalance Settlement. The rules that govern how these two functions are carried out are set down in the Balancing and Settlement Code.

Those persons that are bound by the terms of the Balancing and Settlement Code are collectively referred to as parties. It is anticipated that holders of generation, transmission, distribution/PES and supply licences will be required to be parties to the Balancing and Settlement Code whilst traders and others may choose to become parties to the Code.

4. GATE CLOSURE

It is intended that bulk electricity will be traded by generators, suppliers and traders via a variety of means, including exchanges and bilateral contracts. The quantities of energy purchased and sold in these trades must be notified into the Imbalance Settlement mechanisms in order that they may be taken into account in determining the imbalance position of the parties. Furthermore, because Imbalance Settlement operates half-hourly, the traded quantities will be notified in respect of each half-hour.

It is expected that these trades may, in some cases, be made a year or more in advance of the half-hour to which they relate. Whilst trades may be notified some time in advance they cannot be notified after the event (i.e. after the half-hour to which they relate has passed). Instead, trades must be notified in advance of the half-hour to which they relate. The time limit by which information relating to trades needs to be notified into Imbalance Settlement is called 'Gate Closure' and is initially set at 3 ½ hours ***[reduced to 1 hour in July 2002]*** prior to the start of the half-hour to which it relates. Thus notifications of quantities of electricity purchase and sale for the settlement period 16:30 – 17:00 must be received before 13:00 on the same day. Every half-hour period has its own Gate Closure, set 3 ½ hours ***[1 hour after July 2002]*** prior to the start of the half-hour.

Because quantities of purchases and sales for a particular settlement period must be notified prior to Gate Closure, physical trading of electricity on exchanges and under bilateral contracts is effectively prevented after this time. If, for example, at 14:00, a supplier purchased energy for the period 16:30 – 17:00, it would not be possible for that purchase to be taken into account when determining the imbalance position of that supplier in Imbalance Settlement. This is because the latest time for notification of contract volumes relating to 16:30 – 17:00 is 13:00. The supplier would therefore have to buy the energy to meet its physical demand from the Imbalance Settlement mechanism.

Gate Closure also has a significance that relates to the operation of the Balancing Mechanism. This is discussed further in section 6.

5. THE BALANCING MECHANISM

5.1. Overview

Generators and suppliers differ from pure traders of electricity in that not only do they buy and sell electrical energy under contract, they produce and have customers that consume physical quantities of energy as well. Under NETA, generators will, in general, be free to determine for themselves the level at which their individual generating units will operate. Similarly suppliers will, in consultation with their customers, generally be free to specify their intended levels of demand.

It is likely (although it is not a requirement) that the proposed level of physical operation of generation or demand will be related to the overall contractual position of the associated generator or supplier. Thus, it may be expected that a generator will wish to sell a net amount of energy that is related to its intended level of physical generation. Similarly a supplier may wish to buy an amount of energy that is related to the expected level of physical demand taken by its customers. Again, whilst this may be likely, it is not a requirement, and parties can elect deliberately to be in imbalance should they wish to do so.

Once generators and suppliers have decided on the levels at which they wish to operate, they are required to notify these levels to the System Operator. In practice not all generation and demand will be required to notify these operating levels. This is discussed further in section 6.3.

When notifying their proposed operating level to the System Operator, generators and suppliers may, if they wish, also indicate a willingness to deviate from these operating levels. In exchange for payment, generators may be willing to increase or decrease the output of their generating units, and suppliers may have in place arrangements for their customers to be able to increase or decrease their demand.

To this end, generators and suppliers may submit Offers and Bids into the Balancing Mechanism. Generators and suppliers may both submit Offers and Bids. Offers indicate a willingness to increase the level of generation or reduce the level of demand. Conversely, Bids indicate a willingness to reduce the level of generation or increase the level of demand.

The System Operator may 'accept' particular Offers and Bids placed by generators and suppliers in order to control the national and local balance of generation and demand. This process is described in more detail in the next section.

5.2. Physical Notifications

Generators and suppliers that are required to notify the System Operator of their intended operating level do so by submitting 'Initial Physical Notifications' (IPNs) and 'Final Physical Notifications' (FPNs), in accordance with the requirements of the Grid Code.

An Initial Physical Notification relating to expected operating levels throughout the whole day must be submitted to the System Operator by 11.00am on the day before trading.

A Final Physical Notification relating to proposed operating levels in a particular half-hour must be submitted to the System Operator by Gate Closure.

This information is in addition to the contract information relating to purchases and sales of electricity to Imbalance Settlement (as described above) which must also be submitted by this time (although in the case of contracts, the information is submitted to central settlement and not to the System Operator).

Where submitted, Final Physical Notifications must normally be submitted for individual generating units and for individual demands. This is because the System Operator needs locationally specific information in order to ensure that generation and demand is safely matched locally as well as nationally.

Final Physical Notifications take the form of a minute-by-minute profile of the expected power output or consumption of the relevant generation or demand across each settlement period. The information is specified to the nearest MW. A graphical example of the Final Physical Notification data for a generator and a demand is given below.

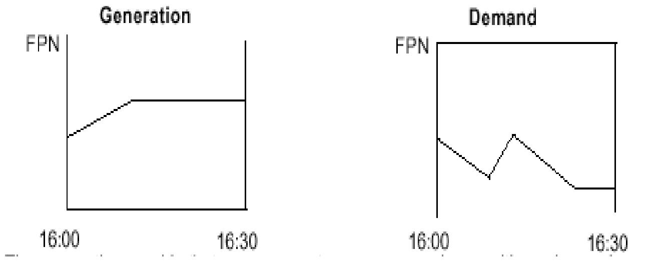


Figure 1 – An example of Final Physical Notifications for Generation and Demand.

The convention used is that power exports are expressed as positive values, whereas imports are expressed as negative values. Thus it is likely that generators will have positive FPNs, and demand will have negative FPNs.

5.3. Requirement to Submit Physical Notifications

Parties responsible for wholesale electricity production and consumption will not necessarily be required to submit Physical Notifications to the System Operator for all generation and demand. In practice, the System Operator does not need information relating to smaller plant (generation and demand) in order to ensure safe operation. For this reason Physical Notifications are only needed when the 'relevant plant' is above a de minimis limit of 50MW.

In this context, 'relevant plant' means a 'BM Unit'. The definition of a BM Unit is discussed in more detail in section 6.4.

5.4. BM Units

The term 'BM Unit' is used to describe collections of generation plant and 'demand plant' that import and/or export electricity, so that physical imports and exports can be treated appropriately under the Balancing and Settlement Code. Because of the number of different types of generation and demand that it must cover the exact definition of a BM Unit is somewhat involved. However, for generating plant, a BM Unit is typically a single generating unit. For demand the definition of a BM Unit is largely dictated by the metering information available to Imbalance Settlement. For large demands, separate metering information is available on a half-hourly basis. In this case, the associated BM Unit is essentially defined as the aggregate of a party's demand behind a single point of connection to the transmission or distribution system. For smaller demand, half-hourly metering information is not available on a site-by-site basis for Imbalance Settlement. Instead, the metering information that is available is the aggregate of small demands supplied by a demand on individual suppliers over 12 different 'GSP Groups'. In this case, the relevant BM Unit is the aggregate of a particular supplier's demand in each of the GSP Groups.

Parties to the Balancing and Settlement Code are required to submit Initial Physical Notifications and Final Physical Notifications to the System Operator by Gate Closure if the associated BM Unit is larger than 50MW (i.e. the BM Unit has a maximum associated import or export in excess of 50MW).

5.5. Participation in the Balancing Mechanism

The BM Unit is the basic unit of participation in the Balancing Mechanism. In order for a BM Unit to be used to provide services to the System Operator in the Balancing Mechanism a Final Physical Notification must be submitted for that BM Unit. Consequently, some parties may also choose to submit Final Physical Notifications for BM Units that are smaller than 50MW if they wish to use these BM Units to offer services in the Balancing Mechanism.

Another pre-requisite for BM Unit participation in the Balancing Mechanism is the requirement to establish appropriate electronic communication links with the System Operator. Under NETA, these links must be electronic in order to handle the large amounts of data transfer. The links are needed for two reasons: first for a party to submit Final Physical Notifications and Bids and Offers for individual BM Units to the System Operator; and second for the System Operator to inform the party when it wishes to call off (or 'accept') Offers and Bids. These issues are discussed in more detail in the next section.

5.6. Offers and Bids

If a BM Unit is to be used to offer services in the Balancing Mechanism, in addition to the Final Physical Notifications, the party also submits Offers and Bids for that BM Unit.

Offers and Bids indicate a party's willingness to operate the BM Unit at a level other than the Final Physical Notification in exchange for payment. They take the form of a set of prices and volumes. An example is given in Figure 2 below.

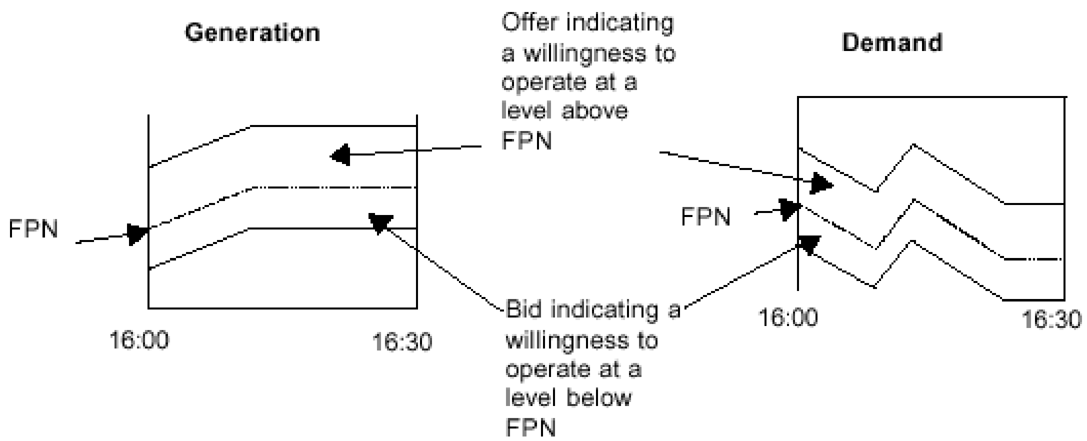


Figure 2 – An example of Offers and Bids

Figure 2 shows a simplified set of Offers and Bids for a generation BM Unit and a demand BM Unit. Offers indicate a willingness to operate above the level of Final Physical Notification, and Bids to operate at a level below Final Physical Notification. (Note that the consumption FPN is a negative value, so 'operating above the FPN' actually means consuming less). If the System Operator wishes to increase the net amount of energy being delivered to the system it may accept an Offer from a BM Unit. If this is a generating BM Unit, then the BM Unit should increase its level of export. If it is a demand BM Unit, then the demand should reduce its level of import.

If the System Operator wishes to decrease the net amount of energy being delivered to the system, then it may accept a Bid from a BM Unit. If this is a generating BM Unit, then the BM Unit should decrease its level of export. If it is a demand BM Unit, then the demand should increase its level of import.

The diagrams in Figure 2 above are simplified because in practice, a party may submit several Offers and Bids for a single BM Unit for a particular settlement period. This means, for example, that the price for operating a generating BM Unit at a level up to 100MW above Final Physical Notification may be £30/MWh, whereas for operating between 100MW and 200MW above Final Physical Notification, the price may be £40/MWh.

A further feature of the Balancing Mechanism is the fact that it is 'firm' on the System Operator. This means, for example, that once the System Operator has informed the relevant party that it wishes to accept an Offer from a BM Unit it is committed to purchasing that Offer. If the System Operator subsequently decides that the initial decision to purchase an Offer was incorrect, then, instead of simply cancelling the original purchase, it must accept a Bid (either from the same BM Unit, or from a different BM Unit if it is economically more efficient as well as physically suitable). This means that for every Offer, there is a complementary 'undo' Bid. Furthermore for every Bid there is an associated 'undo' Offer. For this reason, Offers and Bids are submitted in pairs. These pairs are given numbers to identify them. The numbering convention is such that where the Offers and Bids are for operation above Final Physical Notification, the pair numbers are positive. If they are for operation below Final Physical Notification, the pair numbers are negative.

A more detailed example of the Offers and Bids submitted for a generating BM Unit is shown in figure 3. This highlights the pairing of Offers and Bids.

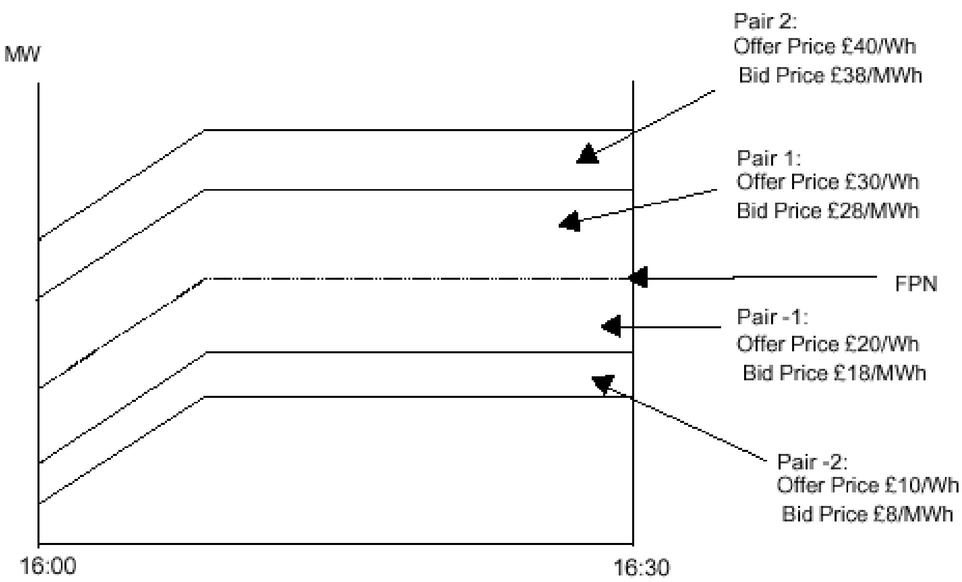


Figure 3 – More detailed example of pairs of Offers and Bids for a generating BM Unit

Offers and Bids therefore indicate the price for different levels of operation relative to the Final Physical Notification. As may be seen from figure 3, an initial restriction under the new electricity trading arrangements is that the level of any pair of Bids and Offers is fixed (relative to FPN) for the duration of the settlement period. In common with Final Physical Notifications, Offers and Bids for a BM Unit applying to a particular half-hour must be submitted by Gate Closure for that half-hour.

5.7. Operation of the Balancing Mechanism

The purpose of the Balancing Mechanism is to provide the System Operator with a means of undertaking several functions as follows: matching system-wide imbalances between electricity production and consumption; adjusting local and bulk power flows to ensure the security of the transmission network; placing BM Units in a position to deliver other Balancing Services. Balancing Services are technical services, purchased by the System Operator. They are required in order to maintain the reliability and security of the transmission and distribution networks. They include services to operate generation and demand plant in a manner that will support system voltage and system frequency.

The operation of the Balancing Mechanism for a particular half-hour starts after Final Physical Notifications and Offers and Bids have been submitted to the System Operator for that half-hour – i.e. after Gate Closure. The System Operator is solely responsible for determining which Offers and Bids are accepted in the Balancing Mechanism. The System Operator may accept all or part of any Offer or Bid at any time after Gate Closure up until real time.

Whilst the System Operator is generally free to accept any Offer or Bid at any time between Gate Closure and real time, the System Operator is required to ensure that any acceptance it makes is consistent with the dynamic parameters of the associated BM Unit. The dynamic parameters of a BM Unit give information relating to the limitations on physical operation of the BM Unit. This include the rates for increasing and decreasing output and input levels, information relating to stable levels of operation, and the maximum levels of import and export that each BM Unit is capable of.

In accepting Offers and Bids, the System Operator will inform the relevant party of the absolute level at which it wishes the BM Unit to operate. In doing so, the System Operator may accept several Offers and/or Bids at once. The set of data issued by the System Operator to the party is called a Bid-Offer Acceptance. A Bid-Offer acceptance is illustrated in Figure 4.

In figure 4, a single Bid-Offer Acceptance has been issued by the System Operator that affects three of the Offers and Bids submitted for the settlement period. From this, the shaded areas in figure 5 show the quantities of Offers 1 and 2, and Bid –1 that are all accepted by the single Bid-Offer Acceptance.

Note the numbering convention for Bid-Offer Pairs is that those above FPN are given positive numbers and those below FPN are given negative numbers.

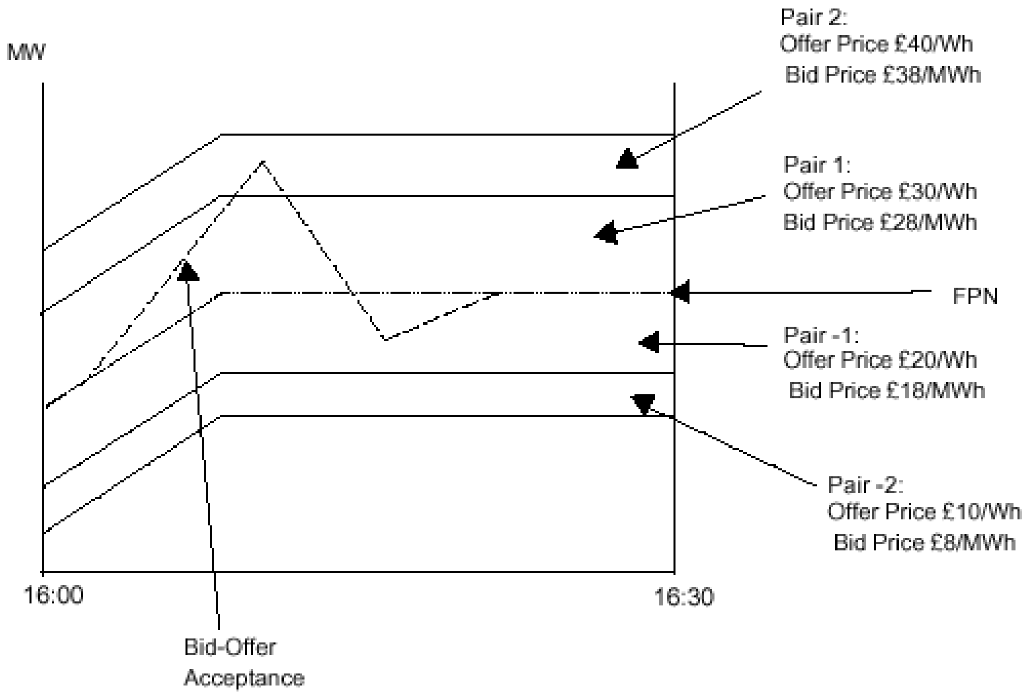


Figure 4 – Accepting Offers and Bids

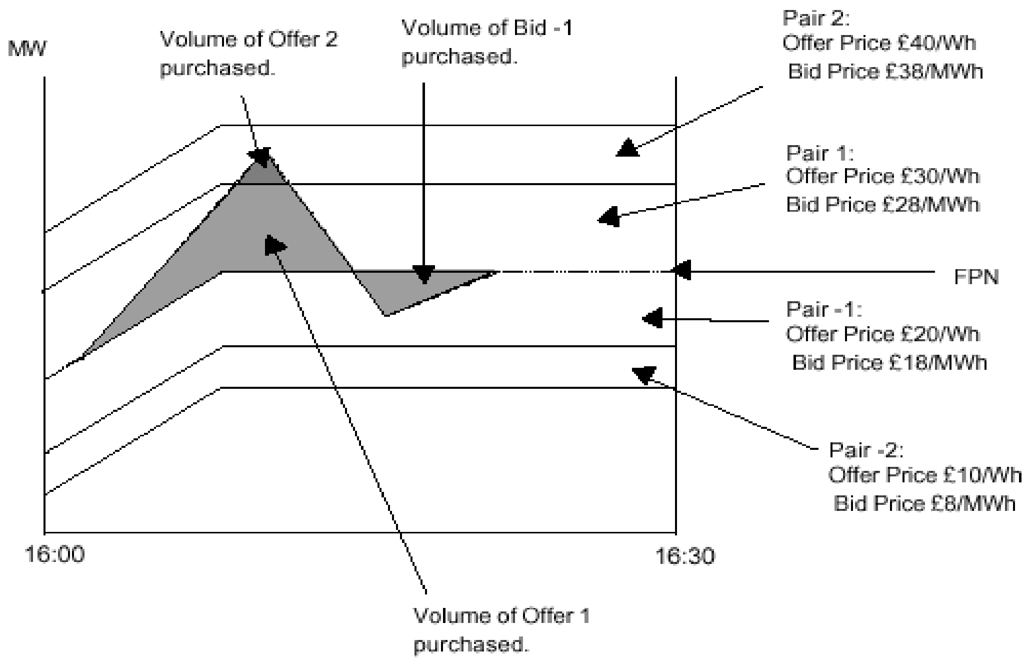


Figure 5 – Volumes of Offers and Bids Accepted

Offers are purchased where the System Operator has requested operation above the level of FPN. Bids are purchased where the requested level is below FPN. Thus in the above diagram, parts of Offers 1 and 2 are initially purchased. Later, half-way through the settlement period, when the requested operating level falls below FPN Bid number –1 is purchased.

As shown in Figure 5 above, the volume of accepted Offers or Bids determined from a single Bid-Offer Acceptance is calculated on a minute by minute basis across the half-hour.

In some extreme circumstances, (e.g. if there are insufficient Offers and/or Bids available for the System Operator to balance the system) it may be necessary for the System Operator to require certain BM Units to operate at a level other than FPN, even if no Offers or Bids have been submitted for those BM Units. In this case, the System Operator will not log an acceptance for the BM Unit in question (because there are no Offers or Bids against which the acceptance may be settled). In most situations there will be an impact on the imbalance position of a party instructed by the System Operator in this way.

The detailed operation of the Balancing Mechanism and the interface between parties and the System Operator will be set down in the Grid Code, and in the Balancing Principles. The Grid Code is a technical document describing the interfaces between those parties that connect to and use the electricity transmission network. It is anticipated that the Balancing Principles will be produced by the System Operator (as a requirement of the Transmission Licence).

5.8. Payment for Offers and Bids

The volume of an accepted Offer or Bid is determined as the volume of the shaded areas in Figure 5. Thus in the example in Figure 5, three MWh values would be determined as a result of the single Bid-Offer Acceptance. These are the MWh of purchase of Offers 1 and 2 and the MWh of purchase of Bid –1.

Accepted Offers and Bids (adjusted to reflect transmission losses) will be settled at the relevant Offer or Bid Price. In the case of Offers, the party responsible for the BM Unit will be paid at the relevant Offer price multiplied by the losses adjusted volume of the accepted Offer.

In the case of Bids, the party responsible for the BM Unit will pay (rather than be paid) at the prevailing Bid price multiplied by the losses adjusted volume of the accepted Bid. The reason why parties are paid for Offers, but are charged for Bids is explained as follows:

A demand BM Unit from which a Bid is accepted is expected to increase its demand. The Bid price therefore simply represents the price that the party is willing to pay for an additional MWh of demand that it had not already purchased under a bilateral contract.

If a Bid is accepted from a generation BM Unit, a reduction in the generation from that unit is expected. The Bid price in this case, simply represents the price that the party is willing to pay to avoid having to actually generate a MWh of energy.

Note that it is possible for both Offer and Bid prices to be negative. If a negatively priced Offer was accepted, the party would be charged for increasing its generating
output, or for reducing its demand. If a negatively priced Bid was accepted, the party would be paid for increasing its demand, or for reducing its generation.

5.9. Arbitrage Offers and Bids

Because parties are paid for accepted Offers at Offer Price and are charged for accepted Bids at Bid price, if one BM Unit has an Offer Price that is less than the Bid
Price of another, the System Operator can in fact save money by making an ‘arbitrage’ trade. This involves simply accepting both the Offer and the Bid.

Note that both parties (i.e. from whom the Offer and the Bid were accepted) should be satisfied with the arbitrage, because they have freely submitted Offers and Bids into the Balancing Mechanism indicating the price at which they are prepared to take the balancing action.

Arbitrage Offers and Bids are treated slightly differently from other Offers and Bids
when calculating energy imbalance prices (see below).

5.10. Non-Delivery Charges

A number of Offers and Bids may be accepted from a particular BM Unit in any particular settlement period. Furthermore, as discussed above, accepted Offers and Bids may be ‘undone’ by accepting an Offer or Bid in the opposite direction. The net amount of Offers and/or Bids accepted in a particular half-hour from a BM Unit will result in a net expected profile for the operation of the BM Unit in that half-hour.

If a BM Unit has a net volume of accepted Offers (i.e. more accepted Offers than Bids), then if the BM Unit shortfalls (i.e. generates less than expected, or imports more than expected) it will be subject to non-delivered Offer charges. If a BM Unit has a net volume of accepted Bids, then it may be subject to non-delivered Bid charges.

Thus non-delivery charges are made if the meter reading for a BM Unit reveals that the BM Unit has failed to deliver its Offers or Bids on an aggregate basis across the half-hour. In the event of non-delivery, the part of any Offer or Bid that is not delivered is charged a non-delivery charge.

6. INFORMATION IMBALANCE CHARGES

Information Imbalance Charges are intended to provide an incentive for parties to operate their BM Units in accordance with their Final Physical Notification modified by any accepted Offers or Bids.

The Information Imbalance Volume for a BM Unit is simply the difference between the metered output recorded over the settlement period, and the level at which the BM Unit should have been operating in aggregate over the half-hour period,

given its Final Physical Notification and any accepted Offers and Bids.
The Information Imbalance Charge is the same irrespective of whether a party generated or consumed above or below its expected level. Thus a BM Unit that 'spills' by 1 MWh is charged the same Information Imbalance Charge as a BM Unit that is in deficit for 1MWh.

Information Imbalance Charges are levied on the party that registers the BM Unit in the settlement system, irrespective of whether the metered output of the BM Unit has been assigned to another party (see section 7). Initially, the Information Imbalance Price will be set at zero, and consequently no charges will actually apply.

7. ENERGY IMBALANCE

7.1. Overview

In addition to the provision of a Balancing Mechanism, the Balancing and Settlement Code provides for the settlement of imbalances between the actual and contractual positions of parties in each settlement period.

As explained in section 3 above, under the new electricity trading arrangements it is expected that bulk purchases and sales of electricity will be made under the terms of bilateral contracts and via electricity trading exchanges. Generators, suppliers and electricity traders are expected to be active in this trading activity. In addition to striking contracts for purchase and sale of electricity, generators and suppliers will also be responsible for physical quantities of electricity production and consumption. Energy Imbalances settlement is needed in order to settle the differences between the net contractual and net physical position of all parties.

Thus, in order to settle Energy Imbalances, it is necessary to determine the metered production or consumption of each party and the net contractual position for each party in each settlement period. It is also necessary to determine the prices at which Energy Imbalances will be settled.

Under the new trading arrangements a two-part cashout of imbalances will be undertaken. The price paid to parties that have a net surplus of imbalance energy will be different from the price that is paid by parties that have a net deficit of imbalance energy.

A further feature of Imbalance Settlement under NETA is that for a single party, two Energy Imbalances will be calculated. Energy Imbalances for 'Production' related activities and 'Consumption' related activities are treated separately. Broadly speaking, 'Production' relates to generation and 'Consumption' relates to demand. The calculation of Energy Imbalance Prices is described in section 8.7 below.

This two-part imbalance arrangement is effected by the calculation of a 'Production Energy Imbalance' and a 'Consumption Energy Imbalance' for each party. Parties are said to hold two Energy Imbalance Accounts, a Production account and a Consumption account.
The level of the Energy Imbalance for each of a party's accounts is calculated as the difference between the metered quantities of generation and demand allocated to each of the accounts and the contract quantities allocated to each of the accounts.

The Production Energy Imbalance will be the difference between the aggregate metered Production allocated to the party, and the net of contract volumes notified to the Production Energy Account. Similarly the Consumption Energy Imbalance will be the difference between the aggregate metered Consumption allocated to the party and the net contract volume notified to the Consumption Energy Account.

7.2. Energy Contract Volume Notification

In order to take account of the quantities of purchase and sale of electrical energy in a particular settlement period in Energy Imbalance, it is necessary for such contract quantities to be notified into central settlement.

If two parties trade electricity (either via a bilateral contract or through an exchange), it is necessary for the parties to notify central settlement of the volume of the contract (in kWh), and to identify which party has purchased the energy and which party has sold it. Note that it is not necessary for central settlement to have any information relating to the price at which energy was bought and sold under the contract in order to determine Energy Imbalance volumes.

Under the new trading arrangements, both parties to a contract must notify the relevant volumes into central settlement through a single agent. The Energy Contract
Volume Notification Agent (ECVNA) acts on behalf of the trading parties, and notifies information relating to the electricity trade into central settlement. This information includes details of the trading parties and the kWh quantities of trade (in addition to passwords etc.). Contract volumes for a particular settlement period must be notified into central settlement (specifically to the Energy Contract Volume Aggregation Agent, ECVAA) by the notification agent prior to Gate Closure for that settlement period.

A single pair of trading parties may nominate any number of Energy Contract Volume Notification Agents to act on their behalf. (One of the parties themselves could be an Energy Contract Volume Notification Agent).

In practice, the information contained in contract volume notifications needs to be slightly more specific about the parties involved in the contract trade. It is necessary to not only identify the parties involved, but the specific Energy Accounts of the parties to which the trade relates. Thus the Energy Contract Volume Notification Agent must identify both the parties and either their Production Energy Account or the Consumption Energy Account. Note that it is possible not only for the Production Energy Account of one party to sell to the Consumption Energy Account of another and vice versa, but also for a single party to notify energy 'purchases' and 'sales' between its own two Energy Accounts.

Subject to some credit monitoring, there are no restrictions on the energy contract volumes that may be notified to and from each account.

7.3. Energy Contract Volume Aggregation

Once received by central settlement, the notified contract volumes are aggregated for each of the Production and Consumption Energy Accounts of each party to determine a net contractual position for each of the accounts. These net contractual positions will be compared to the net metered quantities allocated to each of the Energy Accounts in order to determine the Energy Imbalance for each Production and Consumption Account.

7.4. Production and Consumption and Imports and Exports

In order to determine the metered quantities that need to be taken into account when calculating Energy Imbalances, it is necessary to collect metering data for each BM Unit in each settlement period. This metered data is collected in a number of different ways, but is ultimately used to establish a metered volume for each BM Unit in each settlement period.

Whether the metered volume of a BM Unit will be treated as Production or Consumption (and consequently whether it will be aggregated to the Production or Consumption energy account for imbalance purposes) depends upon the ‘Type’ of the BM Unit - i.e. whether the BM Unit itself is either a Production or Consumption BM Unit.

The Type of a BM Unit is based upon whether, over the year, the maximum level at which it is expected to be exporting over any settlement period is more or less than the maximum level at which it is expected to be importing over any settlement period. It is generally intended that BM Units that comprise generating plant will be Production BM Units and BM Units that comprise supplies will be Consumption BM Units. In practice some BM Units will also be permitted to choose their Type freely.
A further factor to be taken into account in determining the Type of a BM Unit is whether the BM Unit is to be aggregated with a number of other BM Units within a single Trading Unit. In this case, the type of all the BM Units in the Trading Unit is determined on a collective basis.

The metered quantities from the BM Unit will be allocated to the Energy Account type that matches the type of the BM Unit (i.e. Production or Consumption). Thus metered quantities for Production BM Units will be allocated to Production Energy Accounts, and metered quantities for Consumption BM Units will be allocated to Consumption Energy Accounts.

It should be recognised that Production BM Units may, in some settlement periods, import electricity and Consumption BM Units may export electricity. The difference between import and export and Production and Consumption for a BM Unit is animportant feature of the trading rules.

Whether the metered volume associated with a particular BM Unit is treated as an import or an export for settlement purposes depends upon whether its associated Trading Unit has, in aggregate, imported or exported in that particular settlement period. The classification as an import or export affects the treatment of the BM Unit Metered Volume for purposes of transmission loss factor application, and revenue surplus reallocation (see section 10 below).

7.5. Metered Volume Reallocation Notification

So as not to restrict parties’ commercial freedom, it will be possible for the energy flowing to or from an individual BM Unit to be allocated between two or more different parties for the purpose of calculating energy imbalances. (This would allow, as an example, a supplier to notify volumes relating to a share of a customer’s meter, in order to meet that customer’s requirements for partial supply).

By default, the party registering the BM Unit is responsible for the metered quantities arising from the BM Unit. Thus by default, the metered quantities from Production BM Units will be allocated to the party’s Production Energy Account, whereas the metered quantity from Consumption BM Units will be allocated to a party’s Consumption Energy Account.

It is also possible for the party responsible for a BM Unit to reallocate some or all of the metered volume for the BM Unit to another party for any given settlement period(s). As with contract volume notifications, metered volume reallocations must be notified into central settlement by Gate Closure. The information contained within a metered volume reallocation includes identification of the relevant BM Unit and the name of the party and associated Energy Account to which the metered volume is to be reallocated. The information may also contain either a fixed number of kWh to be reallocated from the BM Unit, or a percentage of the metered volume to be reallocated.

The party responsible for a BM Unit is termed the Lead Party, whereas the party receiving the metered volume reallocation is termed the Subsidiary Party.

If a metered volume fixed reallocation is made, the fixed amount is reallocated to the relevant Energy Account of the Subsidiary Party. If a percentage reallocation is made the appropriate percentage of the actual meter reading for the BM Unit is reallocated to the relevant Energy Account of the Subsidiary Party. In each case, the relevant Energy Account of the Lead party is credited with the actual metered output less the reallocated amount.

Any number of percentage reallocation notifications may be made for a particular settlement period for a given BM Unit, however the aggregate of all the percentages must not exceed 100%, nor may negative percentages be reallocated. There are no restrictions on the number or sign of fixed reallocations that may be made in relation to a single BM Unit.

7.6. Energy Imbalance Volumes

The Energy Imbalance Volume for a particular energy account is the net of all metered quantities and contract volumes allocated to that account. The Energy Imbalance Volume for an account may be positive (showing that a net surplus of energy accrued to the account), or negative (showing that a net deficit of energy accrued to the account). For the purposes of aggregation, metered exports are treated as positive values and metered imports as negative.

It is possible for a single party to have a net surplus of energy in one Energy Account and a net deficit in the other in the same settlement period. Two separate charges would be applied in this situation, as discussed further in section 8.7.

7.7. Energy Imbalance Price Calculation

Energy Imbalance Prices are the prices used to settle the Energy Imbalance surpluses or deficits. There are two Energy Imbalance Prices – the System Buy Price and the System Sell Price.

The System Buy Price is the price at which deficits are charged. It is intended to reflect the average price at which the system had to buy in order to make good the deficit on behalf of the party. Thus if an Energy Account has a negative Energy Imbalance, this is charged for at System Buy Price.

The System Sell Price is the price at which surpluses are charged. It is intended to reflect the average price at which the system had to sell in order to dispense with the surplus spill energy. If an Energy Account has a positive Energy Imbalance, this is paid for at System Sell Price.

Energy Imbalance prices are derived from the prices of Offers and Bids accepted by the System Operator in the Balancing Mechanism. System Buy Price for a particular settlement period is calculated as the volume weighted average of accepted Offers relating to that settlement period. System Sell Price for a particular settlement period is the volume weighted average of accepted Bids relating to that settlement period.

In fact, not all accepted Offers and Bids are necessarily used in the calculation of Energy Imbalance Prices. Some accepted Offers and Bids may be excluded from the weighted average calculation because they are flagged as being either ‘arbitrage’ trades or as ‘System Balancing’ trades, (as opposed to ‘Energy Balancing’ trades).

Arbitrage trades are those trades described in section 6.9. Arbitrage trades are easily identified as those accepted Bids and Offers for which the Offer Price is less than (or equal to) the Bid Price.

‘System Balancing’ trades are more complicated to identify. They exist because the Balancing Mechanism is used not just to deal with system-wide energy imbalances. It is also needed in order to provide the System Operator with a means of meeting a variety of more complex system requirements (for example to change a generator’s output so as to change power flows on the transmission system, so that voltages remain within reasonable limits).

System Balancing trades are excluded from accepted Bids and Offers prior to calculating the Energy Imbalance Prices. They are excluded by simply disregarding some of the extremely priced accepted Offers and Bids (i.e. some of the highest prices accepted Offers and some of the lowest priced accepted Bids).

There are a number of other detailed adjustments in the calculation of the prices, for example transmission losses are taken into account in the weighted averaging calculation of Energy Imbalance Prices, and adjustments may be made if the System Operator has entered into certain contracts before Gate Closure.

Under normal circumstances, System Buy Price is expected to exceed System Sell Price.

7.8. Energy Imbalance Cashflows

The term ‘Energy Imbalance Cashflow’ is used to describe the charges or payments that arise as a result of settling Energy Imbalances. Where an Energy Account has a positive Energy Imbalance, it is paid at System Sell Price, and where it has a negative Energy Imbalance, it is charged at System Buy Price.

8. SYSTEM OPERATOR CHARGES

Whilst accepted Offers and Bids are used to determine Energy Imbalance Prices, the costs of operating the Balancing Mechanism are in fact met by the System Operator.

The System Operator is required to pay for the net cost of all accepted Offers and Bids (less any charges arising from non-delivery).

9. REVENUE SURPLUS REALLOCATION

A variety of payments and charges arise relating to various aspects of the Balancing Mechanism and Energy Imbalance settlement for every settlement period. These include payments and charges for accepted Offers and Bids and for positive and negative Energy Imbalances. Furthermore, there are charges for non-delivery of Offers and Bids and for Information Imbalance. Finally the System Operator is charged for the total cost of Balancing Mechanism action.

The net of all these charges and payments in any settlement period is not zero. In general, the net of all the charges and payments will result in an overall surplus of funds in each settlement period. This surplus is reallocated to parties, pro-rated across all metered imports and exports for which each party is responsible in each settlement period.

Note that in the case where a party reallocates metered quantities to a second party via a metered volume reallocation, then it is the second party that receives the pro-rated revenue surplus reallocation. It is anticipated that this may be taken into account when the parties agree the price for the metered volume reallocation in the first instance.

10. SUMMARY

One of the basic principles of the New Electricity Trading Arrangements is that those wishing to buy and sell electricity should be able to enter into any freely negotiated contracts to do so. It is expected that under the new trading arrangements, bulk electricity will be traded on one or more exchanges and through a variety of bilateral and multilateral contracts. Those buying and selling electricity on exchanges and through bilateral contracts are likely to include not only generators and suppliers (who produce or consume physical quantities of electrical energy), but non-physical traders as well.

The objective of the new arrangements is not to dictate how energy will be bought and sold on these exchanges or in bilateral contracts. It is to provide mechanisms for near real-time clearing and settlement of differences between contractual and physical positions of those buying, selling, producing and consuming energy. The following two mechanisms are therefore required: a mechanism by which the System Operator can change proposed operating levels of generation and demand near to real time – the Balancing Mechanism - and a mechanism for settling the differences between net physical and net contractual positions of parties – Imbalance Settlement. The detailed rules associated with these mechanisms will be contained in the Balancing and Settlement Code (BSC).

11. DISCLAIMER

Any information in this document is offered in good faith to assist interested parties in their preparation for the introduction of the New Electricity Trading Arrangements.

However, readers should be aware that some details of the Trading Arrangements may be subject to modification. Readers should also be aware that implementation of the New Arrangements is dependent on the timetable of the Utilities Bill; and that the new Balancing and Settlement Code (BSC), as well as the Implementation Scheme which will govern aspects of the transition from the current Arrangements to the BSC, will only be designated by the Secretary of State after consultation, review (and consequent amendment) of drafts of these documents. Accordingly, the information contained herein should be viewed as provisional. No warranty nor representation is given as to the accuracy of completeness of any of the information provided in this document, and none of the DGES, DTI, NGC, participants in the NETA Programme nor advisors to any of them shall be liable for error, mis-statement or omission.

This document has been produced in accordance with the terms set out in paper DISG 05/010 dated March 1 1999 and which is available from the Programme Director's Office.