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CLIMATE CHANGE GOVERNANCE AND COMPLIANCE

Handout 2

Sections 3 - 8

Section 3: Electricity Markets Supply and Demand – Technical Issues
Section 4: Electricity Markets: Electricity Pool and Deregulation
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5th October 2013

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3. 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 4 and 5 then cover a description of the Electricity Markets in the Privatisation era covering the Electricity Pool (Section 4) and NETA and BETTA in section 5.

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 reduce the current for the same power by a factor of 1000 and at the same time reduce 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

$$W = V \times I \times \cos(\text{ø})$$

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.

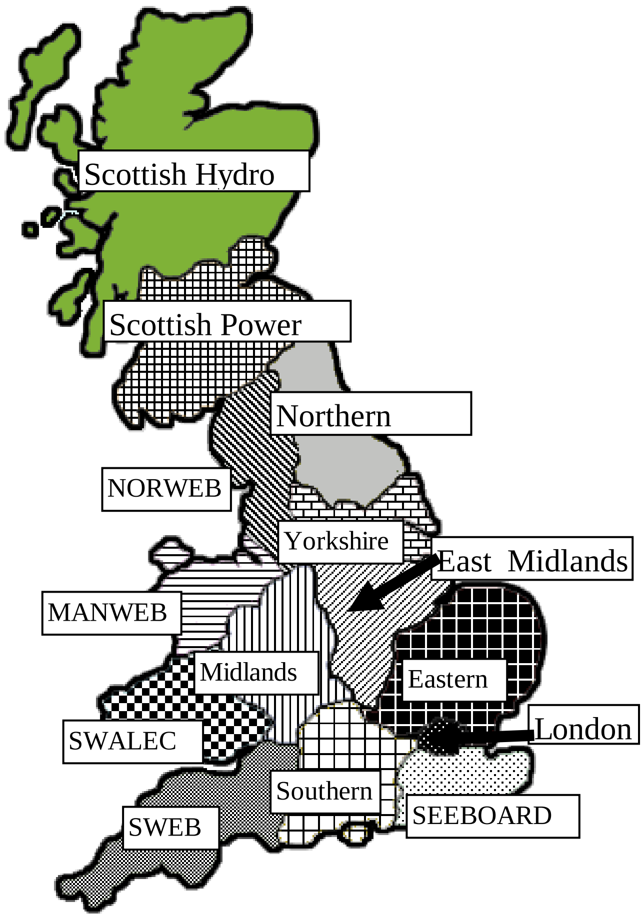


Fig. 3.1 Electricity Area Board pre-privatisation. The regions are still the same to this day, but are now owned by a variety of other companies – see Tables 3.1 and 3.2

Table 3.1 Previous and Current Ownership of Regional Electriciy Companies and Distrobuted Network Operator (DNO) pre-Privatisation, around 1999 and 2010. Until around 1995 the Local Regional Electriciy Company (REC) and the (DNO) were the same company.

Area	Pre 1990	1999	2010	Distributed Network Operator in 2010
South West England	South West Electricity Board (SWEB)	South West Electricity Board (SWEB)	Electricity de France (EdF)	Western Power
Southern England	Southern Electricity Board	Scottish and Southern (merger with NSHB)	Scottish and Southern	Scottish and Southern
South East England	South East Electricity Board (SEEBOARD)	SEEBOARD	EDF	EDF
London	London Electricity Board (LEB)	London Electricity Board	EDF	EDF
Eastern England (East Anglia)	Eastern	Eastern	TXU > PowerGen > E.ON	EDF
East Midlands	East Midlands Electricity Board (EMEB)	PowerGen	E.oN who took over PowerGen	Central Networks (part of E.ON)
Midlands	Midlands Electricity Boards (MEB)	nPower (part of National Power)	RWE nPower	Central Networks (part of E.ON)
South Wales	Sotuh Wales Electricity Board (SWALEC)	SWALEC	Scottish and Southern	Western Power
Merseyside and North Wales	Merseyside and North Wales Electricity Board (MANWEB)	Scottish Power	Scottish Power > Iberdrola	Iberdrola
Yorkshire	Yorkshire Electricity Board (YEB)	Yorkshire	RWE nPower	CE Electric UK
North East England	Northern Electricity Board (NEB)	Northern (NEB)	RWE nPower	CE Electric UK
North West England	North West Electricity Board (NORWEB)	United Utilities	PowerGEn > E.oN	United Utilities
South of Scotland	South of Scotland Electricity Board (SSEB)	Scottish Power	Iberdrola	Iberdrola
North of Scotland	North of Scotland Hydro Board	Scottish and Southern (merger with Southern)	Scottish and Southern	Scottish and Southern

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) privatised 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.

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.

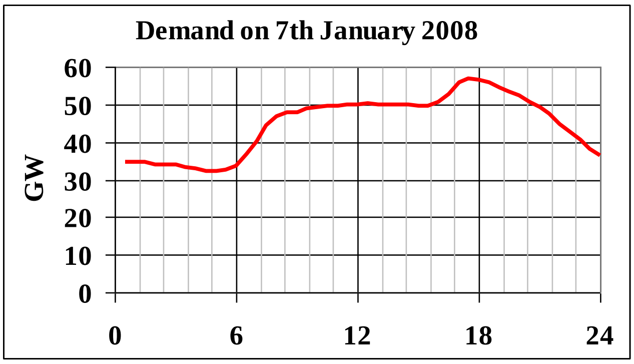


Fig. 3.2 Typical winter weekday (Monday) demand

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

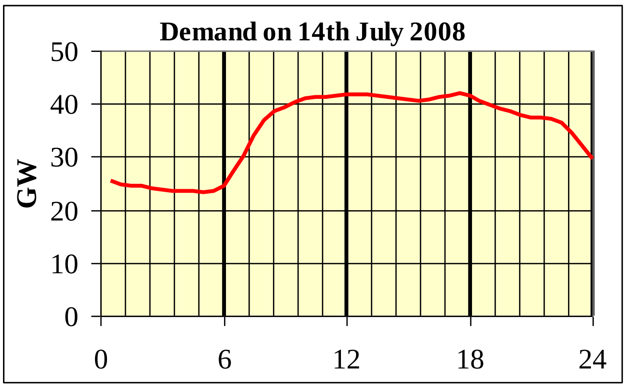


Fig. 3.3. Typical demand in summer on a weekday (Monday)

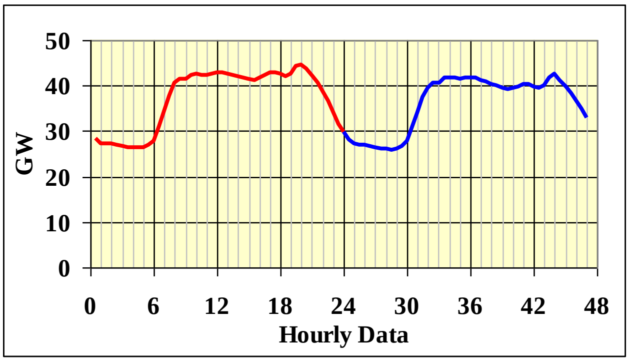


Fig. 3.4 Actual demand data for 24th – 25th September 2008. In winter the peak demand would reach to over 55 GW.

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 forecast ***indirectly*** 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.

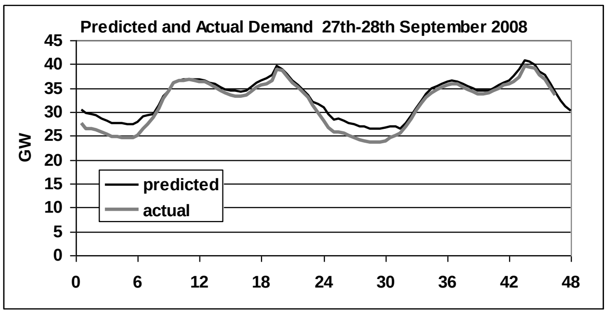


Fig. 3.5. Predicted and Actual Demands. The predictions were made 24 hours in advance. Note: because of a System alert during period 45 on 28th September, there are no data for actual demand between 22:30 and 23:59 on 28th.

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.

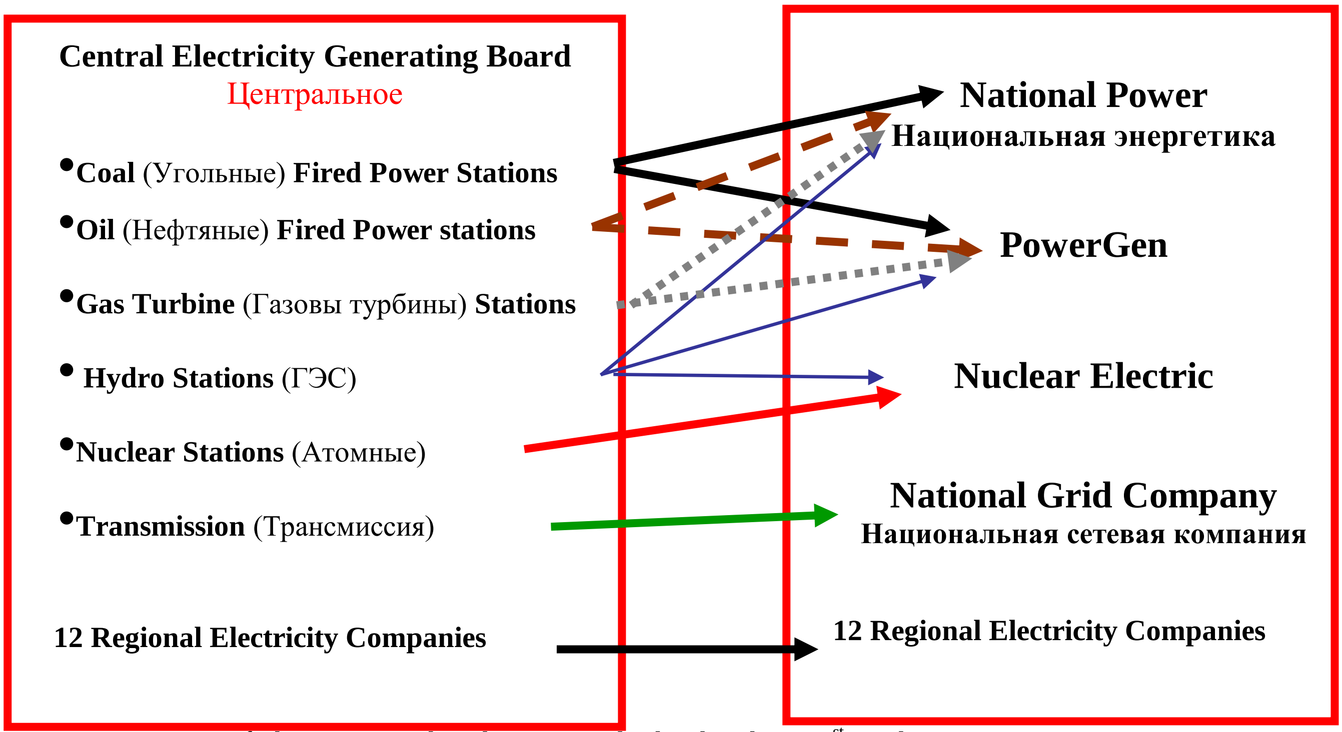


Fig. 4.1 Privatisation of Electricity Supply Industry in England and Wales on 1st April 1990.

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

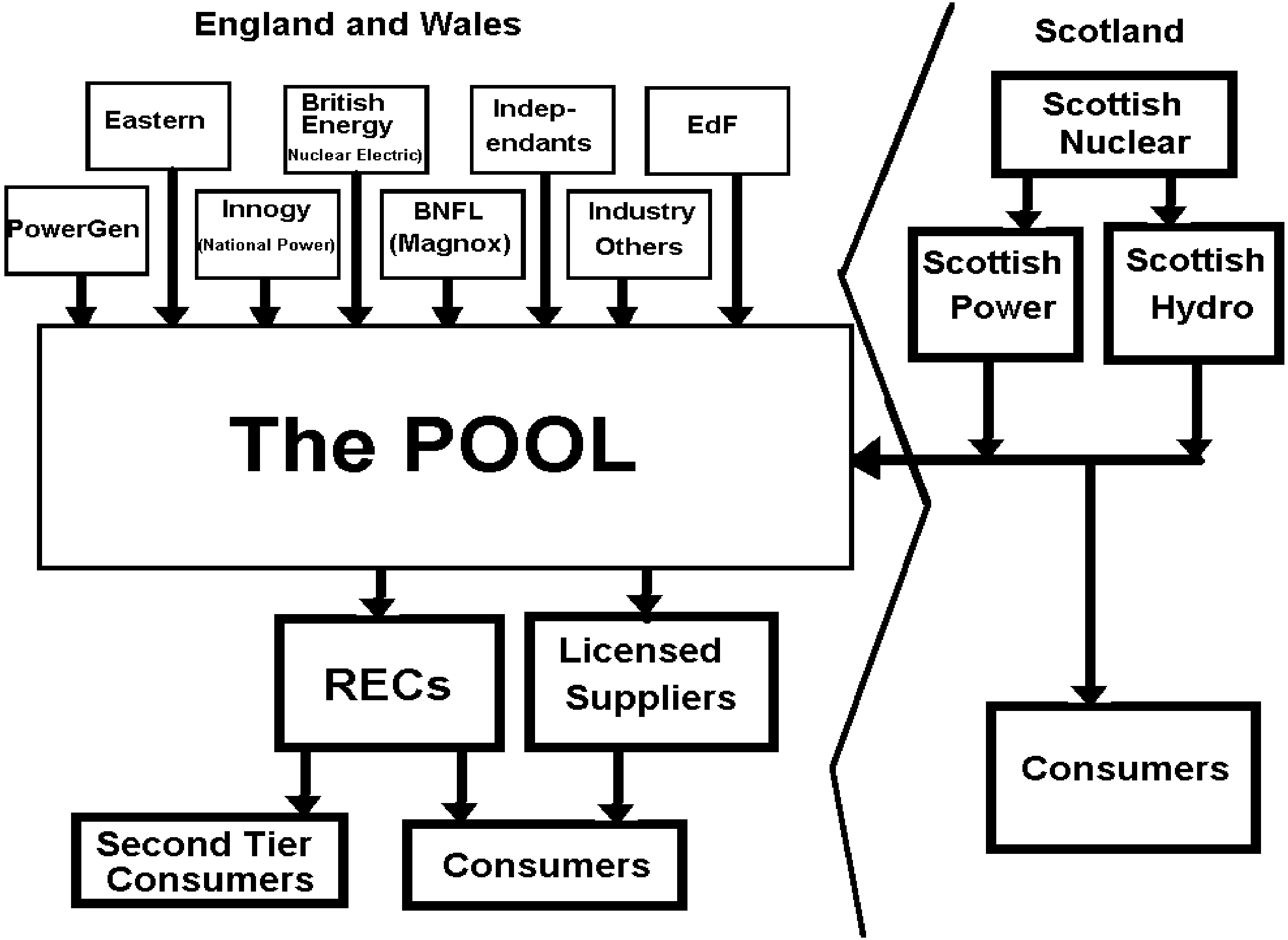


Fig. 4.2. A schematic representation of the Pool as it was in around 1998.

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.

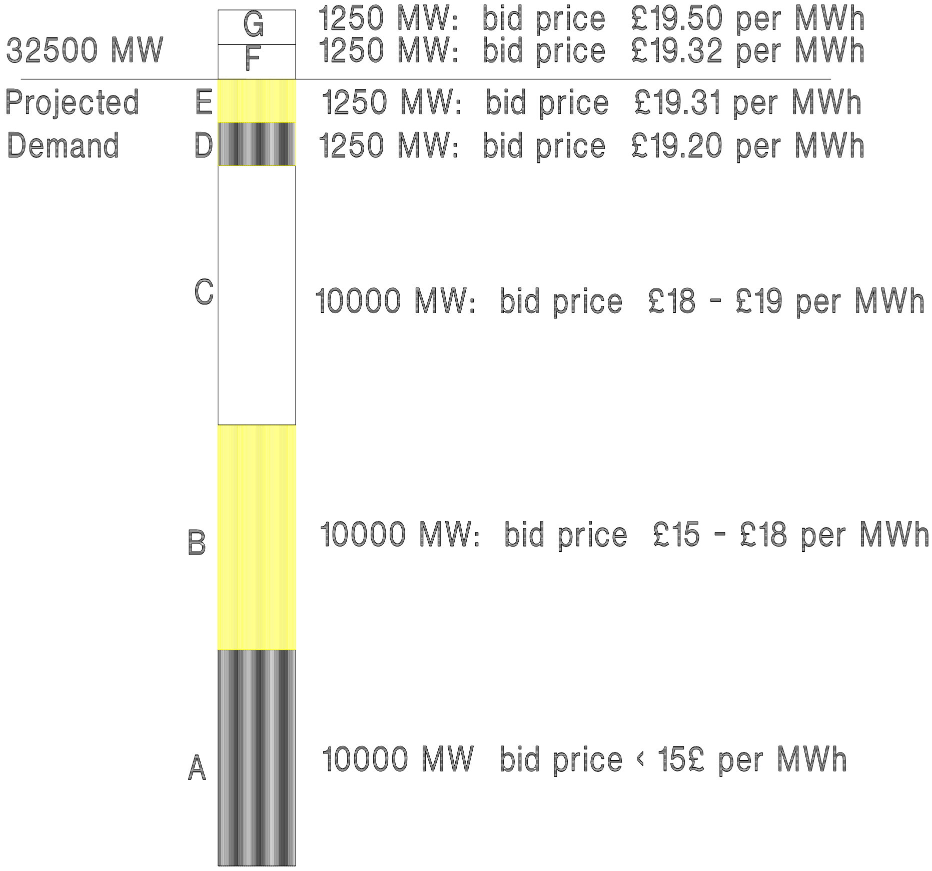


Fig. 4.3 Illustration of the bidding process in the Electricity Pool. The bids were stacked until the required demand level was met. The bid of the highest successful company which bid just below the required demand level set the System Marginal Price (SMP).

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!

4.10. 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 Arrangements (NETA) and developments to the British Electricity Trading and Transmission Arrangements (BETTA)

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.

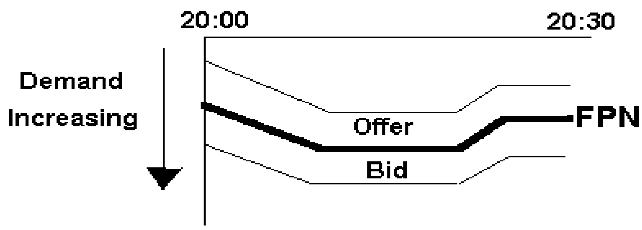
All BM Units (whether generators or suppliers) may in addition to their statutory requirement to notify their contracted supply/demand make an OFFER or BID to change their contractual position after GATE CLOSURE. This OFFER or BID would be between the bM Unit and The System Operator.

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..

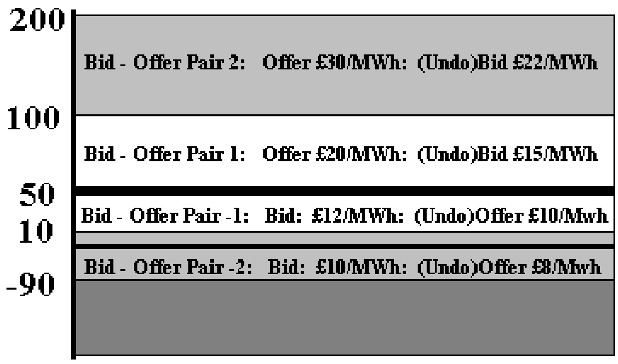


Fig. 5.2 Illustration of multiple bids for different ranges. Also included in this diagram are the Undo Offers and bids.

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

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 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 then 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.

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.

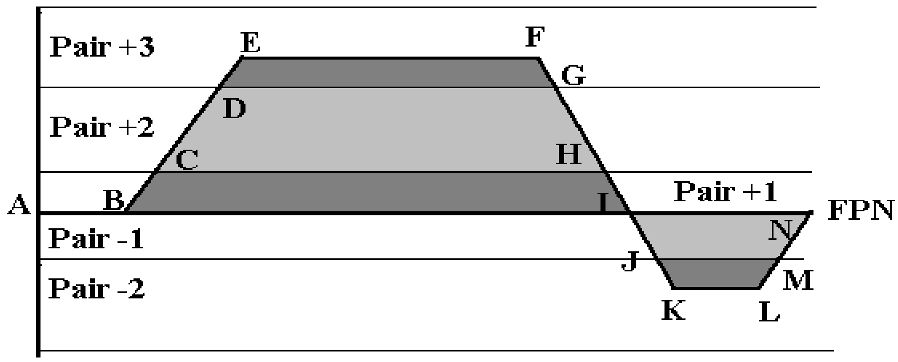


Fig. 5.3 An example of Offers and Bids in a single half hour. Offers are accepted for the first part of the period which sees the level rise above FPN into the region covered by Pair +3. Later in the half hour, BIDS are accepted to reduce the FPN into the region covered by Pair –2. Typical prices of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

The 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. .

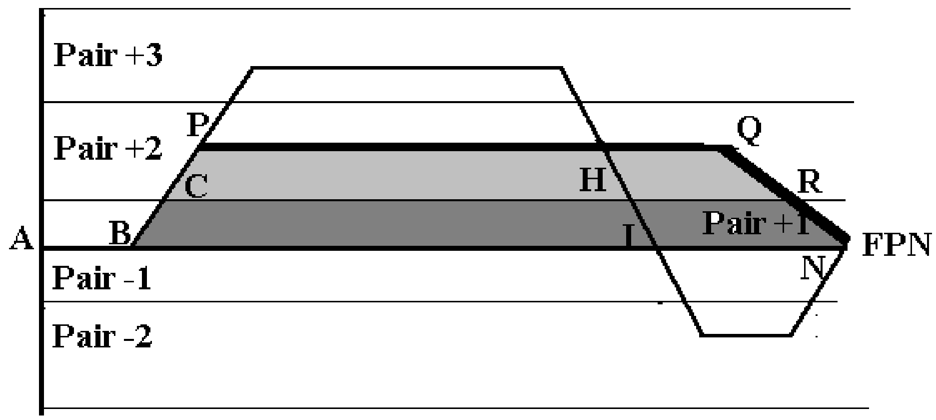


Fig. 5.4 showing revised actual level relative to FPN - A – B – C – P – Q – R – N.

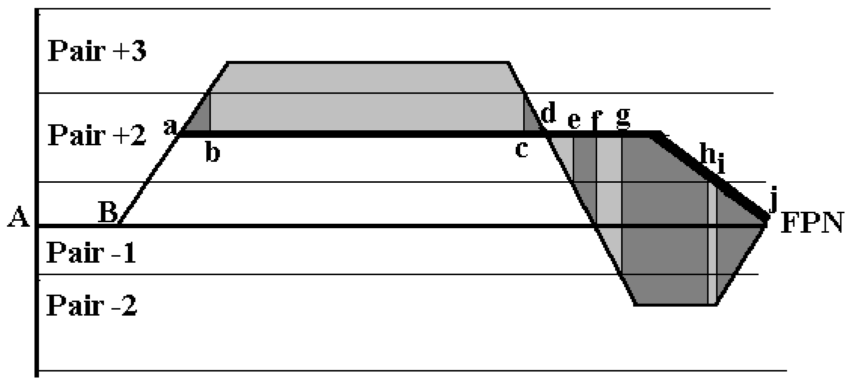


Fig. 5.5 Periods when initial Offers/Bids have had to be cancelled (compare with Fig. 5.3 and 5.4).

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. Currently there is no equivalent of a **"Heat Obligation"** although a consulation document relating to a Renewable Heat Incentive was issued in early 2010**.** However, this would not address the benefits of CHP from fossil fuels – only those from renewable CHP. 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 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).

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

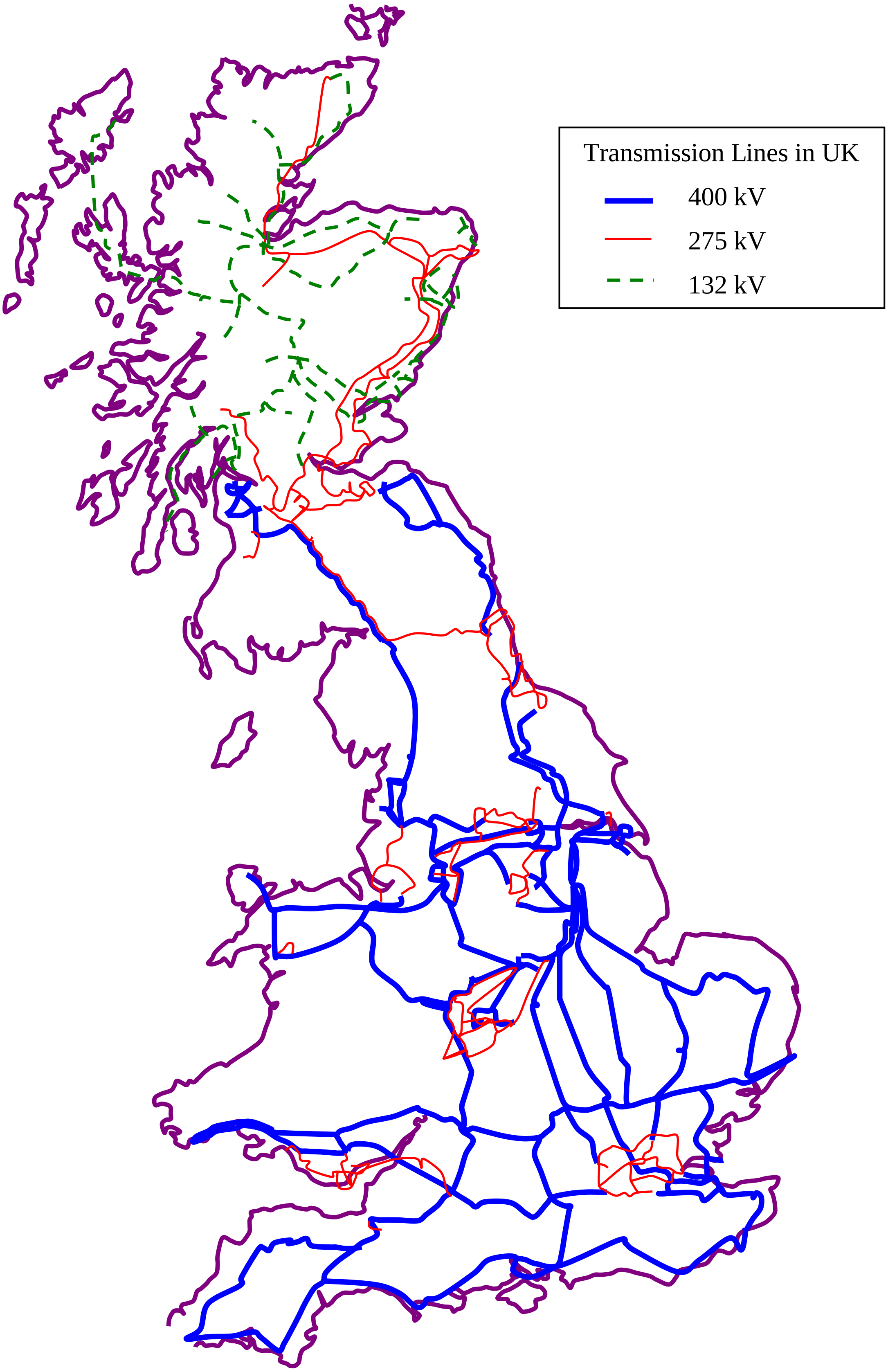


Fig. 5.6 Transmission lines in England, Wales and Scotland

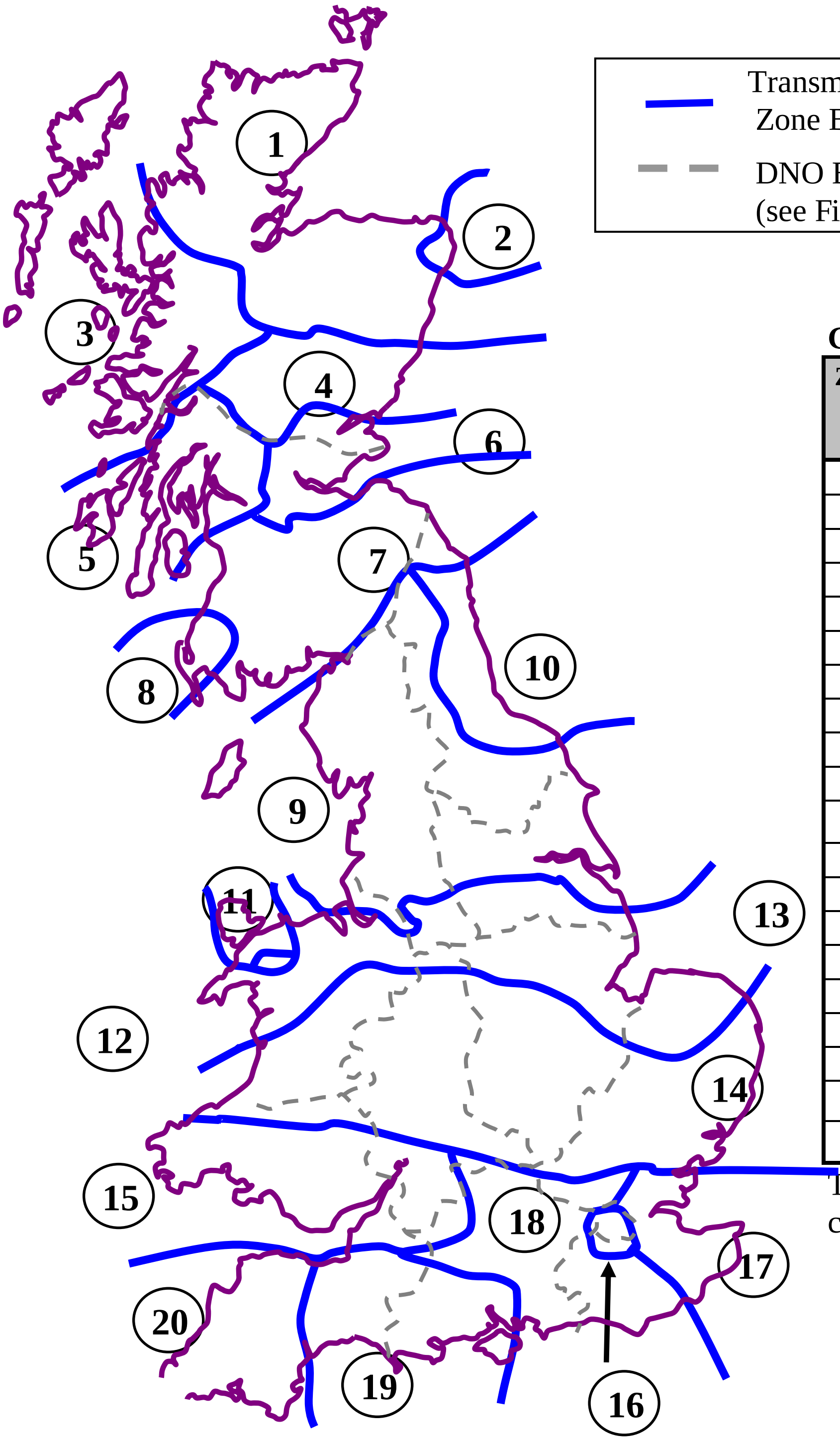
From the implementation of BETTA, there were three transmission Network Licences:

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.



GENERATION: ZONE Charges 2012

Zone No.	Zone Name	Zonal Tariff (£/kW)
1	North Scotland	21.9581
2	Peterhead	20.11314
3	Western Highland & Skye	22.05102
4	Central Highlands	17.56035
5	Argyll	14.18789
6	Stirlingshire	14.22736
7	South Scotland	12.78746
8	Auchencrosh	10.50401
9	Humber & Lancashire	6.078531
10	North East England	8.426476
11	Anglesey	7.099147
12	Dinorwig	6.355495
13	South Yorks & North Wales	4.605096
14	Midlands	2.39287
15	South Wales & Gloucester	2.031854
16	Central London	-13.3507
17	South East	2.324187
18	Oxon & South Coast	-1.10813
19	**Wessex**	-1.708422
20	**Peninsula**	-5.676387

Table 5.3. Annual Transmission Zone charges.

Fig. 5.7 Different Transmission Zonal Charging Regions. The zone charges are reviewed periodically. The figures shown above came into force on April 1st 2012.

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 introduction 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 20 different zones as shown in Fig. 5.7.

The above charges in Fig. 5.7 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. Originally from 2005 the connection charges were constant within a zone and these chargeswere reviewed regularly. However, more recently there has been an additional local charge levied which depends on the specific sub-station to which theconnection is made as shown in Table 5.4.

In addition, to the above charges thereare local connections charges depending on which sub-station is relevant for the connection. 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

Substation	Local Circuit Tariff (£/kW)	Substation	Local Circuit Tariff (£/kW)	Substation	Local Circuit Tariff (£/kW)
Aigas	0.522361	Fallago	0.255780	Lochay	0.255198
An Suidhe	0.981883	Farr	4.792651	Luichart	0.812044
Andershaw	2.205760	Ffestiniogg	0.187549	Marchwood	0.376869
Arecleoch	0.167139	Fallago	0.255780	Mark Hill	-0.598455
Auchencrosh	-0.773760	Farr	4.792651	Millennium	1.256398
Baglan Bay	0.062275	Ffestiniogg	0.187549	Mossford	2.674968
Black Law	2.559142	Finlarig	0.223298	Nant	1.782311
Carraig Gheal	3.099930	Foyers	0.522288	Oldbury-on-Severn	1.322806
Coryton	0.245659	Glendoe	1.772987	Orrin	0.000000
Cruachan	1.209588	Glenmoriston	1.017150	Quoich	2.867907
Crystal Rig	0.031471	Gordonbush	1.163204	Rocksavage	0.011697
Culligran	1.238411	Griffin Wind	1.973700	Saltend	0.247637
Deanie	2.034532	Hartlepool	0.382969	South Humber Bank	0.598087
Didcot	0.584386	Invergarry	-0.496695	Spalding	0.223151
Dinorwig	3.764956	Killingholme	0.397891	Strathbora	1.034265
DunLaw	0.451059	Kilmorack	0.156403	Teesside	0.082599
Earlshaugh	2.148826	Langage	0.453844	Whitelee	1.428725
Edinbane	4.774325	Leiston	0.867609		

Table 5.4. **Transmission Network Use of System Local Circuit Charges (£/kW) in 2010/11**

At the end of September 2010, OFGEM announced a review of thes e charges and the way in which they might be deterring the development of renewable generators because connection charges are much higher in Scotland. On the other hand the resource base is much higher in Scotland so despite these extracharges, the financial models should lead to higher NPVs notwithstanding. There is an opportunity to comment on the document by 17th November 2010 – It is not a formal consulation. See Appendix C and: http://www.ofgem.gov.uk/Networks/Trans/PT/Documents1/TransmiT_Call_for_Evidence_Letter.pdf

In addition to the charges placed on generators, there are also charges for consumption of electricity. These demand charges are based on the 14 historic Regional Electricity Areas. They are charges for transmission. In any of these regions the voltage is stepped down from the transmission voltage of 400 or 275 kV (132kV in some parts of Scotland) to lower distribution voltages progressively of 132kV, 33 kV (sometimes 66kV), and 11kV, and distribution charges are incurred for electricity transmitted over the Distribution Networks which are operated by the Distribution Network Operators (DNO). It is because of the differential transmission and distribution charges that the electricity tariffs vary across the country for all of the suppliers.

The Transmisison demand charges distinguish between small consumers – e.g. domestic and small businesses from those which are metered on a half-hourly basis. These charges fro the 14 zonesareshown in Table 5.5. It should be noted that contrary to the generation charges, the demand Use of System (UoS) charges are least in the North of Scotland and highest in the South West of England.

The first columm in Table 5.5 gives information for large consumers measured on half-hour meters and is based on the TRIAD Demand and is measured as the power (inkWs) drawn at the TRIAD Period. As discussed in section 6. The actual energy consumption tariff is a rate per kWh. , the final column is the amount of the unit charge attributable to transmission in each region.

Zone	TRIAD Demand (£/kW)	Energy Consumed (p/kWh)
N. Scotland	5.865932	0.790954
S. Scotland	11.218687	1.547861
Northern	14.523126	1.993796
North West	18.426326	2.552189
Yorkshire	18.344745	2.520788
N Wales & Mersey	18.891869	2.625780
East Midlands	20.934125	2.886193
Midlands	22.692635	3.184194
Eastern	21.835099	3.026211
South Wales	22.524989	3.028765
South East	24.633810	3.377343
London	26.756942	3.602492
Southern	25.494450	3.537180
South Western	26.057832	3.553243

Table 5.5 Transmission Charges for Demand Areas as delineated in Fig. 3.1 from April 2011. Note these are ordered in the reverse way from the generating tariff. – i.e. charges are hishest in South West.

The TRIAD period refers to three separate 30 minute periods at the time of annual peak demand (usually in December/January). One period is the actual period of highest demand, but the two two are periods of highest demand which are separated by at least 10 days from the original peak of highest demand. The power value used in the above table is the mean of the power demands over the three 30 minute periods.

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. They also devolved their functions such that in many areas the local Distribution Company is no longer the Regeional Electricity Supplier. Thus in East Anglia the Regional Electricity Supplier is E.oN while the DNO is EdF. The current ownership is shown in Table 5.6

Table 5.6 Current Ownership of RECs and DNOs

<table>
<tr><th>Zone Name.</th><th>Local REC</th><th>DNO</th></tr>
<tr><td>Northern Scotland</td><td colspan="2">Scottish and Southern (British)</td></tr>
<tr><td>Southern Scotland</td><td colspan="2">Scottish Power / Iberdrola (Spanish)</td></tr>
<tr><td>Northern</td><td>nPower - German</td><td>CE Electric</td></tr>
<tr><td>North West</td><td>E.oN - German</td><td>United Utilities</td></tr>
<tr><td>Yorkshire</td><td>nPower - German</td><td>CE Electric</td></tr>
<tr><td>N Wales & Mersey</td><td colspan="2">Scottish Power / Iberdrola (Spanish)</td></tr>
<tr><td>East Midlands</td><td>E.oN- German</td><td rowspan="2">Western Power</td></tr>
<tr><td>Midlands</td><td>nPowe -German</td></tr>
<tr><td>Eastern</td><td>E.oN - German</td><td>EdF</td></tr>
<tr><td>South Wales</td><td>Scottish Power / Iberdrola (Spanish)</td><td>Western Power</td></tr>
<tr><td>South East</td><td colspan="2">Electricité de France</td></tr>
<tr><td>London</td><td colspan="2">Electricité de France</td></tr>
<tr><td>Southern</td><td colspan="2">Scottish and Southern (British)</td></tr>
<tr><td>South Western</td><td>EdF</td><td>Western Power</td></tr>
</table>

5.10 A review of the impact of NETA

Apart from the impact on Renewables and CHP as discussed in section 5.7. There have been several other consequences 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).

The Government hailed 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.

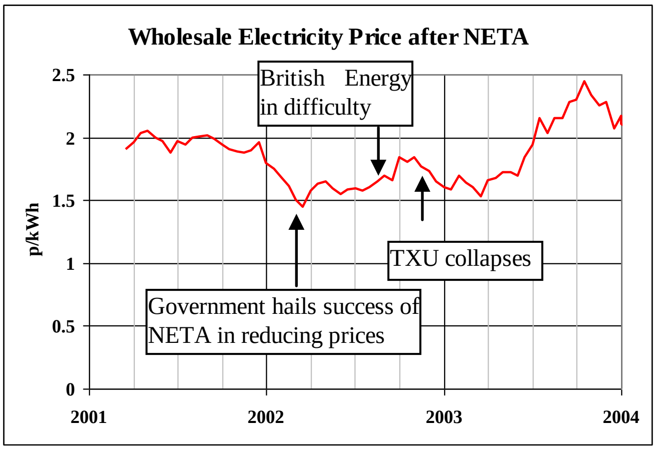


Fig. 5.8 Variation of wholesale prices in first few years after introduction of NETA.

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 Langeled gas pipe lines, but prices then rose sharply followed by a comparable fall. For the last twelve months they have stabilised at around the 4p per kWh level (Fig. 5.9) .

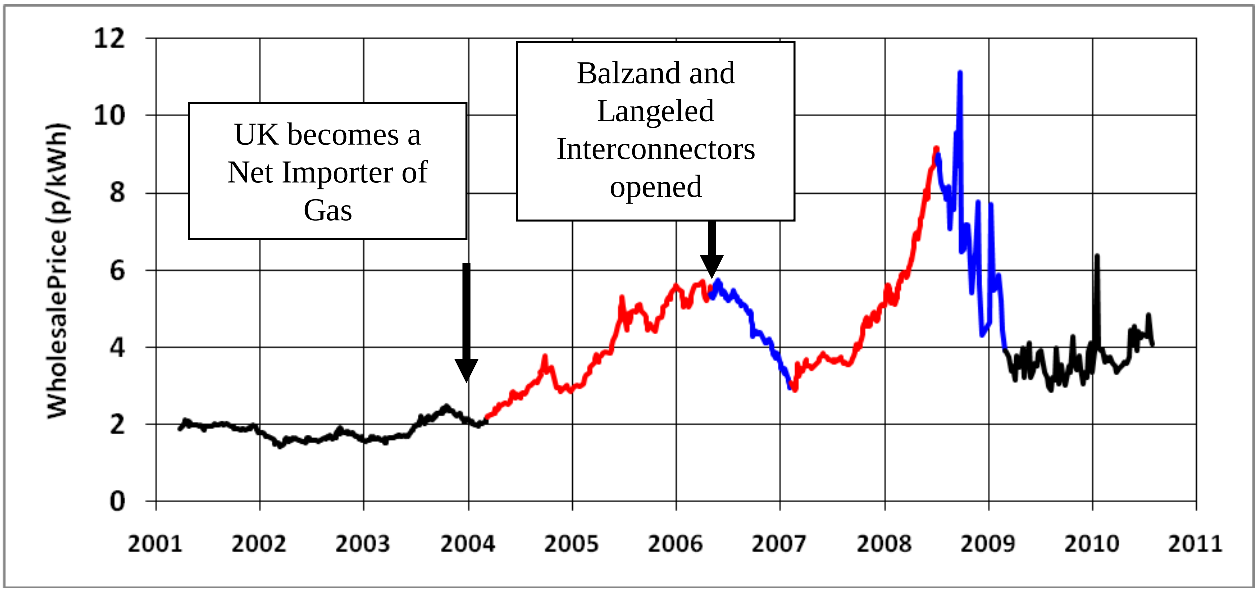


Fig. 5.9 Variation in wholesale price of electricity since introduction of NETA.

Additional Information:

Three papers written in both English and Russian are available at:
http://www2.env.uea.ac.uk/gmmc/energy/NBS-M009/Moscow_papers.pdf. These give more information on NETA and also the developments which led up to BETTA.

6. The TRIAD and the impact on Demand Transmission Charges.

In section 5, Table 5.5 indicated transmission demand charges and included data covering the so-called Triad Demand. This TRIAD demand is an attempt to account for electricity drawn by premises at times of peak national demand. The TRIAD period during which the charges are assessed runs from the 1st November to 28th/29th February and is, in effect a smoothed estimate of the maximum demand. Table 6.1. shows the daily peak demands for the winter of 2008-2009.

Table 6 –Daily Peak Demands over the Triad Period 2008 – 2009 – the three periods of the TRIAD are shown highlighted.

Monday	01/11/2008	35	50880	13/12/2008	35	54618	24/01/2009	35	55363
Tuesday	02/11/2008	35	50663	14/12/2008	35	55191	25/01/2009	35	54774
Wednesday	03/11/2008	35	51121	15/12/2008	34	55876	26/01/2009	35	54053
Thursday	04/11/2008	35	51152	16/12/2008	35	54799	27/01/2009	35	53879
Friday	05/11/2008	35	48734	17/12/2008	35	55008	28/01/2009	36	52232
Saturday	06/11/2008	36	45018	18/12/2008	36	51964	29/01/2009	36	50319
Sunday	07/11/2008	35	45623	19/12/2008	35	50465	30/01/2009	36	49453
Monday	08/11/2008	35	52870	20/12/2008	35	55015	31/01/2009	36	54304
Tuesday	09/11/2008	35	52956	21/12/2008	35	54353	01/02/2009	36	54658
Wednesday	10/11/2008	35	52249	22/12/2008	35	53510	02/02/2009	35	55195
Thursday	11/11/2008	35	50573	23/12/2008	35	48756	03/02/2009	36	53427
Friday	12/11/2008	35	49790	24/12/2008	26	41460	04/02/2009	36	51197
Saturday	13/11/2008	36	43923	25/12/2008	35	41009	05/02/2009	37	47565
Sunday	14/11/2008	35	44553	26/12/2008	35	43812	06/02/2009	36	48051
Monday	15/11/2008	35	50614	27/12/2008	35	48120	07/02/2009	36	54702
Tuesday	16/11/2008	35	50234	28/12/2008	35	49807	08/02/2009	36	54543
Wednesday	17/11/2008	35	50584	29/12/2008	35	49173	09/02/2009	37	54880
Thursday	18/11/2008	35	49567	30/12/2008	35	49251	10/02/2009	39	54716
Friday	19/11/2008	35	48163	31/12/2008	35	45354	11/02/2009	36	53728
Saturday	20/11/2008	35	43102	01/01/2009	35	49050	12/02/2009	36	50885
Sunday	21/11/2008	35	44081	02/01/2009	35	50294	13/02/2009	37	49424
Monday	22/11/2008	35	51328	03/01/2009	35	57085	14/02/2009	36	53438
Tuesday	23/11/2008	34	50807	04/01/2009	35	56301	15/02/2009	37	53037
Wednesday	24/11/2008	35	50836	05/01/2009	35	55954	16/02/2009	37	53594
Thursday	25/11/2008	35	51027	06/01/2009	35	58049	17/02/2009	37	53792
Friday	26/11/2008	35	50738	07/01/2009	35	56961	18/02/2009	37	51948
Saturday	27/11/2008	35	46564	08/01/2009	36	53021	19/02/2009	37	48310
Sunday	28/11/2008	35	46011	09/01/2009	35	52312	20/02/2009	37	48156
Monday	29/11/2008	35	53522	10/01/2009	35	57194	21/02/2009	37	54491
Tuesday	30/11/2008	34	53416	11/01/2009	35	56430	22/02/2009	37	54157
Wednesday	01/12/2008	35	56401	12/01/2009	35	57137	23/02/2009	37	52829
Thursday	02/12/2008	35	52882	13/01/2009	35	57327	24/02/2009	37	52187
Friday	03/12/2008	35	53099	14/01/2009	35	54426	25/02/2009	37	49922
Saturday	04/12/2008	35	46214	15/01/2009	36	49592	26/02/2009	37	46349
Sunday	05/12/2008	35	45089	16/01/2009	36	48317	27/02/2009	38	46342
Monday	06/12/2008	35	53237	17/01/2009	35	54231	28/02/2009	37	53450
Tuesday	07/12/2008	35	52753	18/01/2009	35	53491			
Wednesday	08/12/2008	35	52799	19/01/2009	35	54691			
Thursday	09/12/2008	35	53434	20/01/2009	35	53620			
Friday	10/12/2008	35	53148	21/01/2009	35	52884			
Saturday	11/12/2008	36	48444	22/01/2009	36	48733			
Sunday	12/12/2008	35	49007	23/01/2009	36	48589			

The TRIAD represents three half hour periods during each winter as determined below. Electricity is dispatched and traded on a half hour basis and data of the mean demand in each half hour period over the year is published on the following website:

www.bmreports.com

This half-hour information is used to assess the TRIAD demand. It is assessed from three separate half hour periods:

1) The period of maximum half hour demand during the Triad Period – which usually occurs in December or January although not always..
2) A second highest peak half hour, but with the provisio that it must be separated by at least 10 days from the peak defined in (1),
3) A third highest peak half hour but with the proviso that it must be separated from both periods defined in (1) AND (2) by at least 10 days.

Electricity is traded on a half hour basis and the half hours are denoted as periods such that period 18 with be the period up to 09:00 in the morning. The three periods defined above always occur on a weekday and the period of maximum demand as defined under the TRIAD is almost always in period 35 or 36 on a day in December or January.

From Table 6.1 the maximum demand during the winter of 2008 – 2009 occurred on Thursday January 6th. during period 35 and was 58051 MW. Inspection of data from other days shows that the other two periods forming the TRIAD were period 35 on Wednesday 1st December (56401 MW) and period 35 on Wednesday 15th December (55876MW).

Table 8.2. Demand Transmission

Zone	TRIAD Demand (£/kW)	Energy Consumed (p/kWh)
N. Scotland	5.865932	0.790954
S. Scotland	11.218687	1.547861
Northern	14.523126	1.993796
North West	18.426326	2.552189
Yorkshire	18.344745	2.520788
N Wales & Mersey	18.891869	2.625780
East Midlands	20.934125	2.886193
Midlands	22.692635	3.184194
Eastern	21.835099	3.026211
South Wales	22.524989	3.028765
South East	24.633810	3.377343
London	26.756942	3.602492
Southern	25.494450	3.537180
South Western	26.057832	3.553243

It should be noted that there were other periods which exceeded those periods on 24th January and 14th December – e.g. Thursday 13rd January (period 35) at 57327 MW, but that period was not 10 clear days from the peak demand. There is an EXCEL spreadsheet which can be downloaded from the Course WEB Page which gives the daily actual demand for each day the following year in December 2009 and January 2010.

The Triad Demand charges vary across the country but are highest in the south where demand exceeds generation.

For those companies with half hour metering (typically with and energy demand comparable with UEA or above), the demand charges will be based on the mean demand at the three TRIAD points. Since, at least in December and January the peak demand almost always occurs in period 35, there is scope to minimise the TRIAD charges as indicated in Table 8.2.

Since the introduction of the TRIAD in 1990 the earliest date of the 1st TRIAD was 17th November in 1992 when the demand reached 44600 MW. In that year the 2nd and third points of the TRIAD were on the 9th December and 4th January. The latest date for the 1st point of the TRIAD was on the 7th February 1991.

Since 1990 there have only been four occasions when the first point of the TRIAD has not been in December or January, and only on one occasion since 2000.

For those companies with half hour metering (typically with and energy demand comparable with UEA or above), the demand charges will be based on the mean demand at the three TRIAD points. Since, at least in December and January the peak demand almost always occurs in period 35, there is scope to minimise the TRIAD charges as indicated in Table 8.2.

Fig. 6.3 shows a manufacturing company with 24 hour operation. The processes are of a batch nature and the figure shows the typical demand for the process in December/January together with the , administration demand which is only active between around 08:00 and 18:00 and also the total demand.

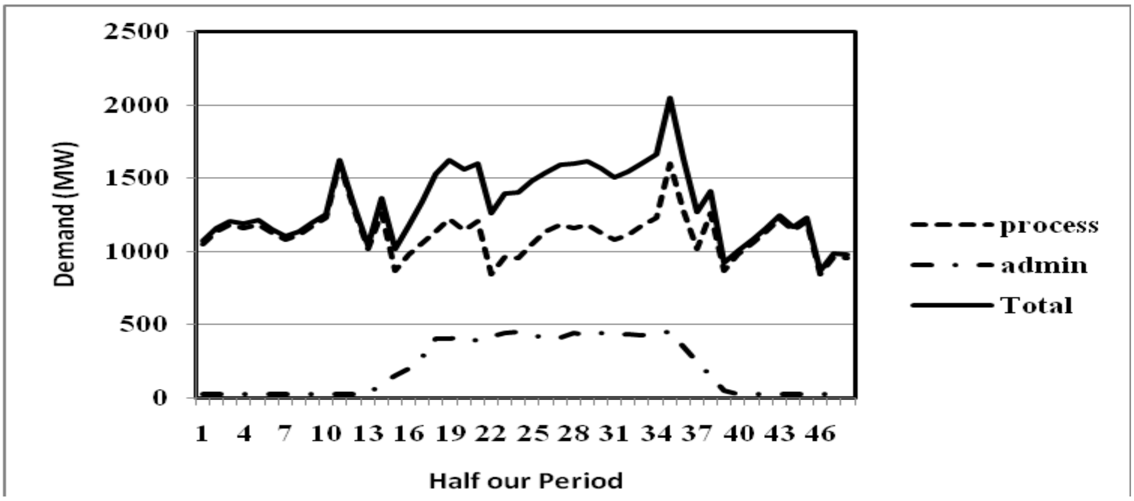


Fig. 6.3. Typical December/January Profiles for a manufacturing company.

It will be noted that the peak demand of the company occurs in period 35 as 2053 kW – precisely at the time of the TRIAD. If the company were based in the South West then the TRIAD charge paid by the supplier and passed on to the company would be

2053 * 26.057832 = £53497

It is noted that the primary cause of the peak company demand is primarily that of the manufacturing process. If the process timing cycle was put back by 2 hours then the revised profile is shown in Fig. 6.4.

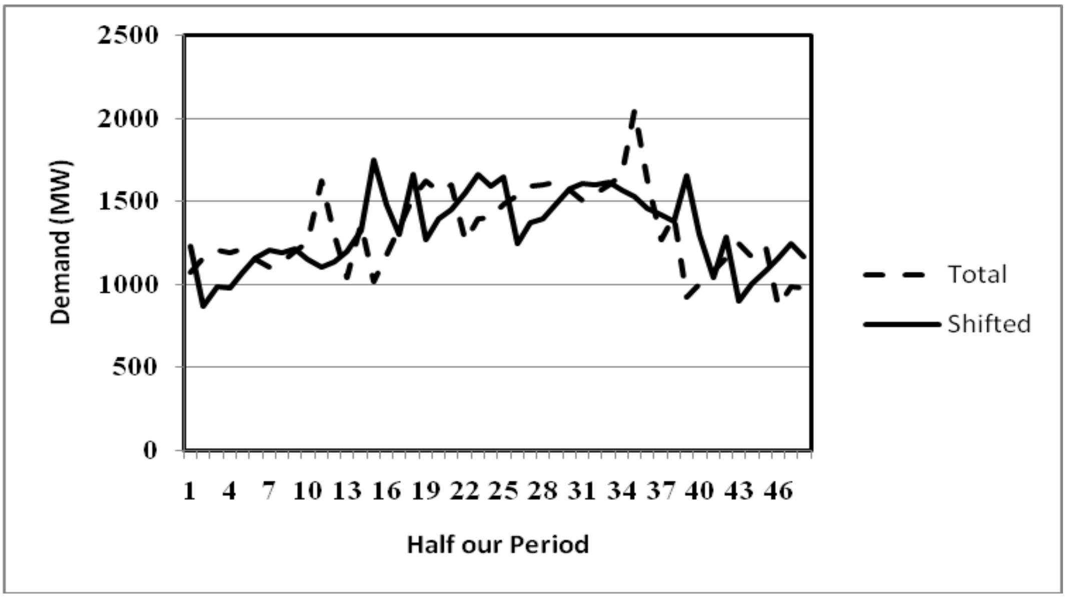


Fig. 6.4. Revised company demand after shifting process timing by 2 hours.

Note the peak in the process demand now occurs after the administration demand has dropped off and the demand in the critical period 35 is much lower at **1530MW**, and this would incur a TRIAD charge of **£39868** a saving of **£13628** or **25.4%.**

It should be noted that this saving arose pureply by examining the demand profile and taking steps to shift the peak. If this had been coupled with technical energy saving measures, the the savings could be even higher.

The carbon emission factor varies significantly over the day and is highest at the time of peak demand when the less efficient fossil fuel power stations are brought into operation. If as a result of action the national peak demand could be lowered, this would be a particularly effective measure for reducing carbon emissions.

7. Diversity of Supply: The Shannon-Wiener Index

7.1 Diversity of Supply

In recent years there has been increasing concern over issue of Energy Security, particularly in the Electricity Supply Industry as over the next five years to 2015, the UK will be loosing the majority of its nuclear generation capacity and also 40+% of its coal generation. In the past the UK was largely dependant on coal and nuclear generation, although oil did become a significant player also during the 1970s and 1980s. While energy resources are indigenous to the UK, the question of energy security is of limited concern and the security of electricity supply will depend on the diversity of distribution of power stations and to a less extent on fuel source. However, with increasing demands for imports of all fuels diversity become important, particularly when some fuel sources such as gas are relatively low carbon.

Within Ecology there is measure of biodiversity using the Shannon Index (H) which is defined as

$$\mathbf{H = -\sum p_i \ln p_i} \qquad \text{..........(1)}$$

where $\mathbf{p_i}$ is the proportion of the ith species of all species.

NOTE: this formula may be found in section 11.10 of the School of Environmental Sciences Data Book.(Page 155 of the 10th Edition).

In a similar was the Shannon-Wiener Index is used in Electricity supply as a measure of diversity with $\mathbf{p_i}$ being the proportion of generation by the ith fuel (e.g. gas).

This index has the same formula as above and is sometimes incorrectly referred to as the Shannon-Weaver Index.

If there is only one fuel then H itself is zero, but will increase for two reasons:

1) If the number of fuels increase
2) Depending on the relative distribution of proportions of the different fuels.

If there n fuels are used then the maximum value the Index can take is shown in Table 1 and Figure 1.

TABLE 7.1. Variation of H with number of fuels used.

Number of fuels used	Shannon-Wiener Index
1	0.000
2	0.693
3	1.099
4	1.386
5	1.609
6	1.792
7	1.946
8	2.079
9	2.197
10	2.303

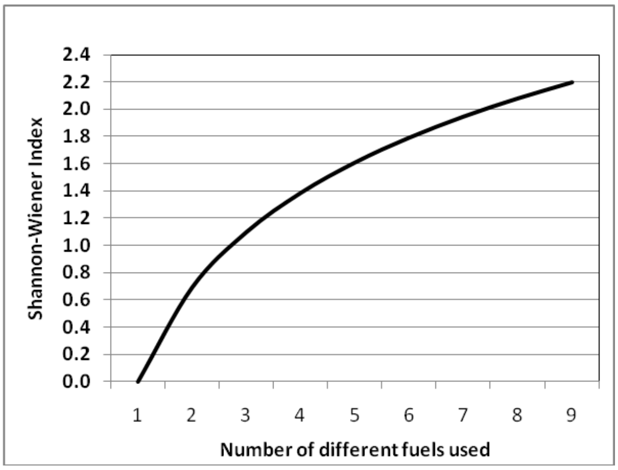


Fig. 7.1 A plot of data in Tables 1.

Notice this means that there is no upper limit to the value the Index may take, and care must be taken in using the Index. Thus supposing six different sources of fuel are used to generate electricity – coal, gas, oil, nuclear, hydro, other renewable, then the maximum value the index can take is 1.792, although that would only actually occur if all six fuels were used in equal proportions.

If on the other hand the category "renewable" was divided into say wind, solar, biomass – now making eight fuel sources in all, the index could potential have a value of 2.079.

This means that it is not valid to compare different systems as the demarcation between fuels may differ. However, it does form a sound basis for tracking the performance of a given country or an organisation over time as specific definitions can be given as to the degree of subdivision etc.

Fig. 2 shows how the Shannon-Wiener Index varies when there are three fuels in different proportions. The figure clearly shows that the index is at a maximum when all three fuels are in equal proportions.

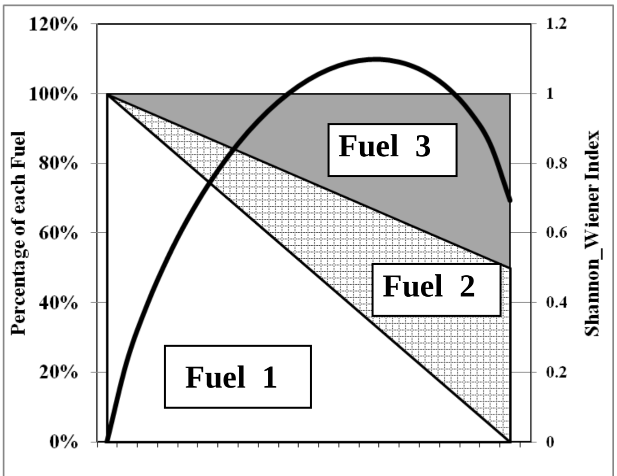


Fig. 7.2 Shannon-Wiener Index with 3 fuels

Table 7.2 shows the amount of electricity generated with each fuel when there are 5 categories of fuel

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Table 7.2. Amount of Electricity generated by each Fuel Type in the UK

	Amount Generated (TWh)			
	2000	2010	2015	2020
nuclear	78.3	55	27.3	21
coal	139.8	122.1	85.7	77.9
oil	6.2	3.8	3.8	3.8
gas	127.8	174.3	215.7	221.2
renewables	6	26.1	54.1	76
Total	358.1	381.3	386.6	399.9

To evaluate the Shannon view factor, it is first necessary to calculate the fractions (percentages) of each fuel type as shown in Table 7.3.

Table 7.3. Fraction generated by each fuel

	Fraction generated by each fuel			
	2000	2010	2015	2020
nuclear	0.219	0.144	0.071	0.053
coal	0.390	0.320	0.222	0.195
oil	0.017	0.010	0.010	0.010
gas	0.357	0.457	0.558	0.553
renewables	0.017	0.068	0.140	0.190
Total	1.000	1.000	1.000	1.000

Using equation 1, the H factor for each fuel may be calculated – e.g. for 2010 the results are shown in Table 7.4.

Table 7.4. Calculation of Shannon-Wiener Index for 2010.

	2010
nuclear	0.279
coal	0.365
oil	0.046
gas	0.358
renewables	0.184
sum	**1.231**

It can be seen that the Index is 1.231 and this should be compared with the maximum for five fuels of 1.609 from Table 7.1.

As an exercise investigate how the Index is likely to change in coming years.

The carbon emission factor varies significantly over the day and is highest at the time of peak demand when the less efficient fossil fuel power stations are brought into operation. If as a result of action the national peak demand could be lowered, this would be a particularly effective measure for reducing carbon emissions.

8 Registered Power Zones

8.1 Introduction

Whenever anew power station however large or small isconnected to the National transmission or Distribution Grid, there must be sufficient capacity on that grid to transportthe electricity generated. There are inevitable losses and these may be summarised as:

Losses = $I^2 R$

Where I is the current flowing and R is the resistance of the conductor. It is thus important to keep the current as low as possible.

The other governing equation is

Power = Volts (E) x Currnet (I)

So for the same power transmission raising the voltage with lower the current and significantly reduce the losses. It is for this reason that voltages are transformed up for transmission and down again to be at a relatively safe level for end use. For instance suppose 1 MW of electricity is to be transmissted along a conductor then the reductions in the losses at different voltages are shown in Table 6.1.

Table 6.1 Relative losses for transmission of power at different voltages

Voltage	%loss relative to 240 V
240	100.0%
11000	0.047603%
33000	0.005289%
132000	0.000331%
400000	0.000036%

The losses are manifest ina heating of the cables and even if the voltages are high (e.g. 400kV), the temperature of the conductors can rise to 50 – 70oC. As the temperature rises so will the expansion of the cable and the sag will incre\se which could cause a flashover. In any cdase over heating can damage peripheral equipment suchas transformers. Thus there is a mximum limit of the power capacity which can be connected to any given transmission line.

Clearly this is a dynamic situation as if there is also demand within the area supplied by the cable, this can increase the generation capacity that can be connected in transmission..

Historically it has been the case that the first generation capability to connect to system has priority rights and subsequent connections are based on a "***first come first served connected.***"

The situation is somewhat different for demand connections apart from last single users. For a large user a similar situation with regard to generation applies. Thus UEA has connection rights of around 6.5 MW from the early years. Demand has grown and some times reaches 5MW+. If the upper limit is reached then UEA would be involved in the expense of reinforcing the local network. This is a charge which can be offset against the cost of providing additional onsite generation as the net power drawn from the local grid would be less.

However for smallscale/domestic consumers a diversity factor is applied for demand requirements on the basis that not all domestic consumers will have all the ir appliances on simultaneously. In fact the actual maximum demand is probably only 20-25% of total potential demand because of this diversity.

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Traditionally a fossil fuel power generator will have a rated maximum output. Often in operation it will either be shut down producing no power or generating at its rated output. Apart from transient periods during run up or run down the majority of the time will be spent at either the rated output or zero output. A few plantmay be designated for balancing when there output might vary over short periods.

The basis for generation connection has been to assume that once a connectionhas been made which potentially allows the rated output of the generator is could be called upon at any time. Once the total capacity of the line has been allocated in this was it will prevent any further connection unless the capacity of the line is upgraded.

For fossil fuel generation this has typically not been a serious issue. However, with the development of increasing amount of renewable generation and particularly large scale wind this can lead to ineffective use of line capacity at periods of low generation. However there must also be security to ensure the lines are not overloaded.

8.2 The Orkney Registered Power Zone

The idea of Registered Power Zones (or Renewable Power Zones) was first suggested around 2002-2003 to get around the problem that Orkney has a substantial potential for Renewable Energy and yet there are major constraints because of "***grandfathering***" rights on the connection rights to the existing Grid. Orkney is connected to the Scottish Mainland by two 30 MW cables which also supply the majority of the power. The Old Kirkwall Power Station (18MW) has been retained to be used in cases where there is an interruption to the cross Pentland Firth Cables.

There is another fossil fuel power station at Flotta the Oil Terminal which is generating most of the time for safety reason. After that there are a few connections with Grandfathering Rights such as the European Marine \Energy Contre at Stromness and the Burgar Hill Wind Farm. However the cumulative effective of all these connections would soon fill up the whole of the available capacity of one of the cable links. It had to be assumed that in the worst case scenario that one of the cables would be out of action and therefore unable to export surplus power.

The minimum demand on Orkney is around 7MW although the Peak demand is much higher.

The idea behind RPZ is to ensure that all potentially available generation capacity can generated subject to the limit that the overall local network must not be overloadedand that might mean switching some generators off at times, but not denying them the ability to actually connect at other times.

How it would work would involve dynamic monitoring of the generation and demand and determining the excess of firm "***grandfathered***" generation over demand at that time. Both the grandfathered generation and the demand will both be varying, but the difference between the net generation and the system line capacicities would them be open potentially to other generators (in Orkney's case mostly Wind). If wind speeds were low, then the turbines would in generally not be running at their rated output and the system could cope. However as the wind speed picked up the total wind generation would cause an excess generation over the same momentary limit and in a RPZ some generators (wind turbines) would be throttled back or shut down to keep the capacity within safe limits.

Unlike the previous situation where under periods of low wind, the liens would significantly under utilised, such an operating regime would make much better use of the capcity available allowing much more renewable generation to connect without the needfor grid strengthening.

A signficantly increased amount of new generation capacity can be connected. The basic heirachy is that those existings firm capacity generators would generated first and regulated connections would then be added on a "***first come first served basis***". If the wind speed picks up and generation capacity exceeds the limit then the last generator to connect would beasked to reduced output or stopand so on. The rational behind this is that those connecting earlier should have modelled into their finances a limited down time whne they were constrained and those requersting later connections would have to take more risk by having less opportunity in running their machines when the wind conditions are optimum.

Orkney has received grants of around £280000 to develop the methodology of such a active power regulation system. Such costs can be offset agains the cost of the alternative which would have required a significant reinforcement of the local network. It is projected that the Net Present Value will be around £700000.

8.3 Other Registered Power Zones.

Several of the DNOs are now considering Registered Power Zones, two which seem to now be actively under way are:

- Lincolnshire – Central Networks
  http://www.eon-uk.com/downloads/RPZ_Skegness_Project.pdf
  This project is also associated with a large offshore wind development, but the project is exploring climatic aspects which could be usedto enhance the performance of the cables. Thus in winter when wind output is at its peak, it also coninsides with coolerambient temperatures leading to greater cooling of the lines and consequently less sagging. Equally the higher windspeeds will also provide additional cooling.
- Martham – EDF.

8.4 Registered Power Zones / Active demand Control

RPZ'scan be seen asa forerunner active Smart Netwroks wqhich potentially could make more effective use of networks through not only active generation despatch, but also active demand control. Two interesting developments will potentially arise in the domestic market:

- Widespread deployment of electric vehicles
- Widespread deployment of electric heat pumps.

With widespread deployment of electric vehicles a problem could arise with drivers plugging their cars in on return from work/shopping in the late afternoon as shown in Fig. 6.1. Such an action would place a substantial strain on the grid requiring substantial investment in new generation capacity which would only be used for a short period of time each day meaning that the return of capital would be very low.

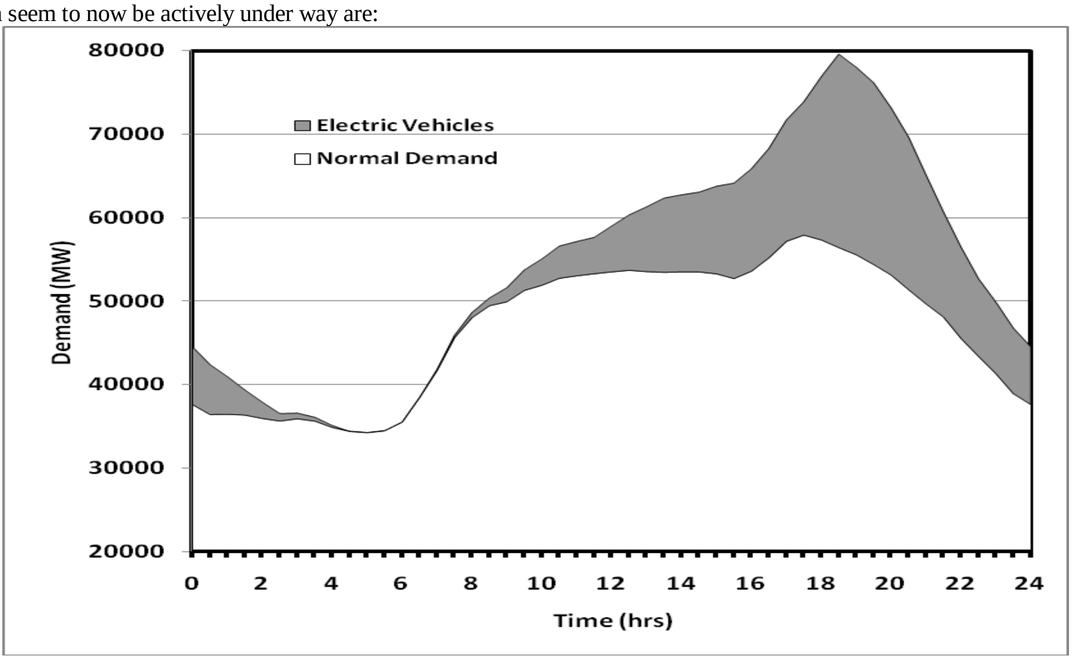

Fig. 8.1 impact on Electricity Demand of a significant shift towerds Electric Vehicles for a January weekday. There would be a substantial peak coinciding with peak normal demand. Data derived from presentation by Dave Openshaw (21st July 2010) http://www.eeegr.com/uploads/DOCS/778-20100726131949.pdf.

There are several strategies which could be adopted to mitigate against this. The first would be to ensure that no charging could take place at peak normal demand – i.e. not between 17:00 and about 21:00. Socially this might not be acceptable for those who wished to go out in an evening, but a way around this would be to allow differential tariffs such that if a vehicle were indeed charged at peak times, they would pay a substantial surcharge on the charging, but if delayed till late in the eveing a reduced tariff would apply. The effect of this can be seen in Fig. 6.2. In this example it is assumed that up to 75% of people would be willing to take advantage of the reduced tariff but that 25% would choose to charge "on demand". There could readibly be a charging facility which defaulted to the delayed tariff, but could be overridden on occasions by a suitable button. The improvement in the load profile is immediately obvious.

There is a further opportunity for smoothing the demand as most cars would have a residual charge in them at the end of the day. Let us suppose that this charge amounts to 25% on average and that 25% of electric vehicle owners would agree to this advanced tariff which would result in a significant discount in tariff. As the car is plugged in say around 17:30, the battery is drained to help smooth out the normal peak and with a large number of vehicles this could have a noticeable effect resulting in more efficient use of normal generating capacity. This effect is also shown in Fig. 6.2. The peak demand has been reduced from just under 80GW to around 65GW.

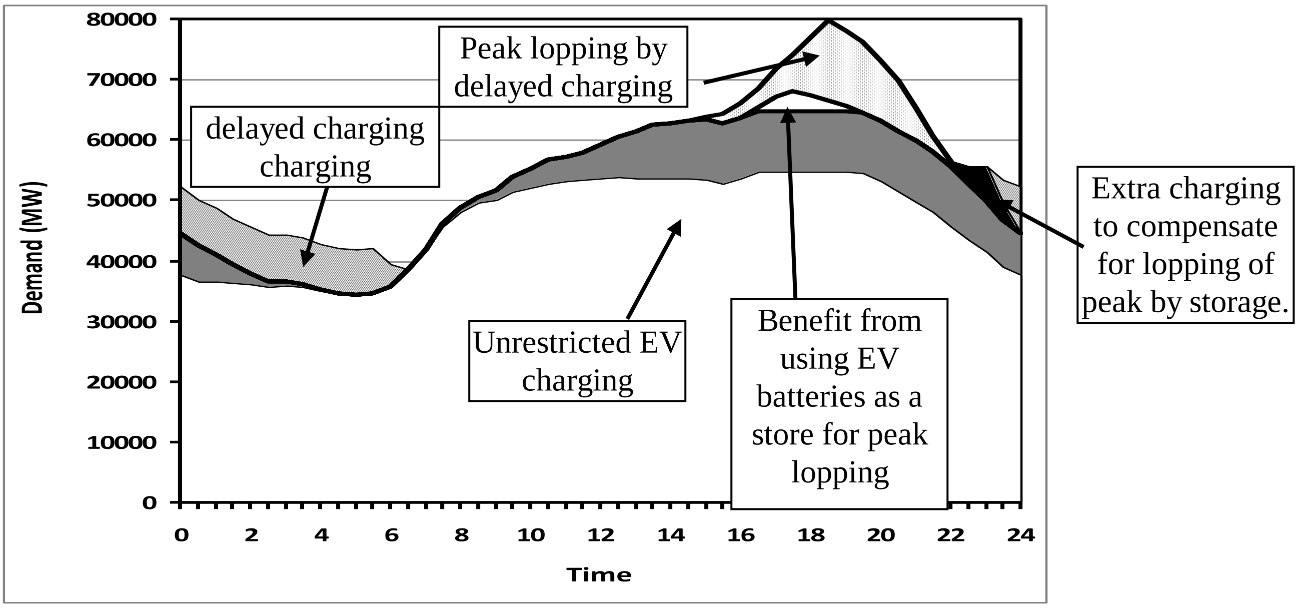

Fig. 8.2 Same overall demand as in Fig. 6.1 but with effective management of charging of electric vehicles as described in text. This simulation done by N.K. Tovey

A similar situation will arise with extensive use of heat pumps. A projected profile for a significant number of heat pumps in operation is shown in Fig. 6.3. The demand from heat pumps is less peaky than the electric vehicles as there is opportunity to use underfloor. heating with an overnight charge of heat to smooth out the diurnal load and improve the utility of installed capacity. As a result the tariffs for overnight charge should be noticeably lower. However, there is merit in considering the use of additional thermal stores so that greater use of overnight electricity can be used as simulated in Fig. 6.4.

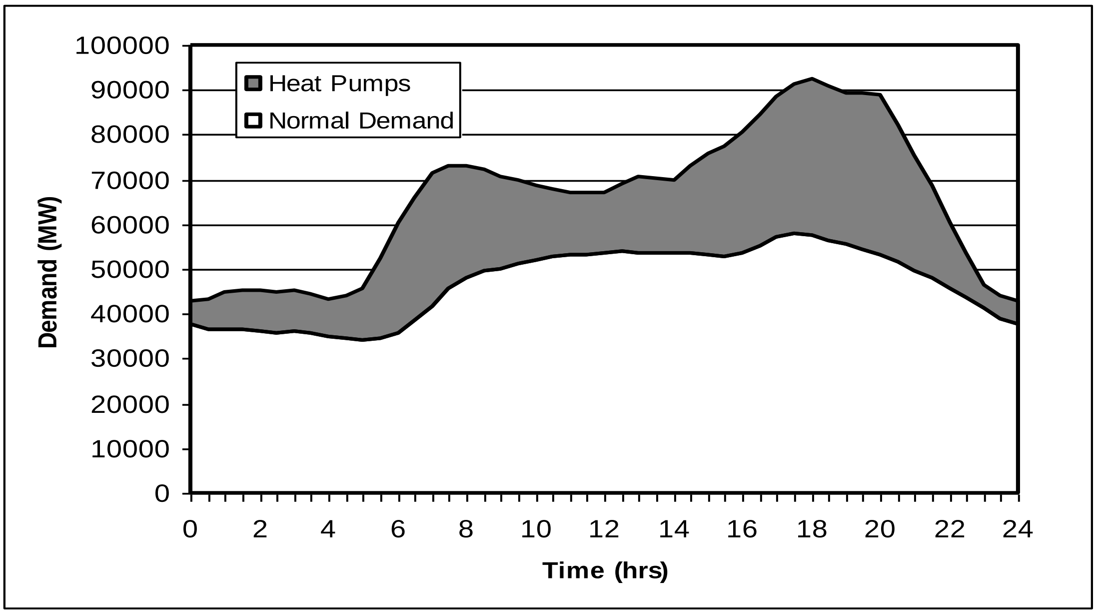

Fig. 8.3 Impact on Actual electricity demand of significant deployment of heat pumps. Unlike the unrestricted electric vehicle profile there is still a demand overnight from those schemes using underfloor heating which acts as a significant store. This heat pump profile was derived from data presented by Dave Openshaw (21st July 2010) http://www.eeegr.com/uploads/DOCS/778-20100726131949.pdf.

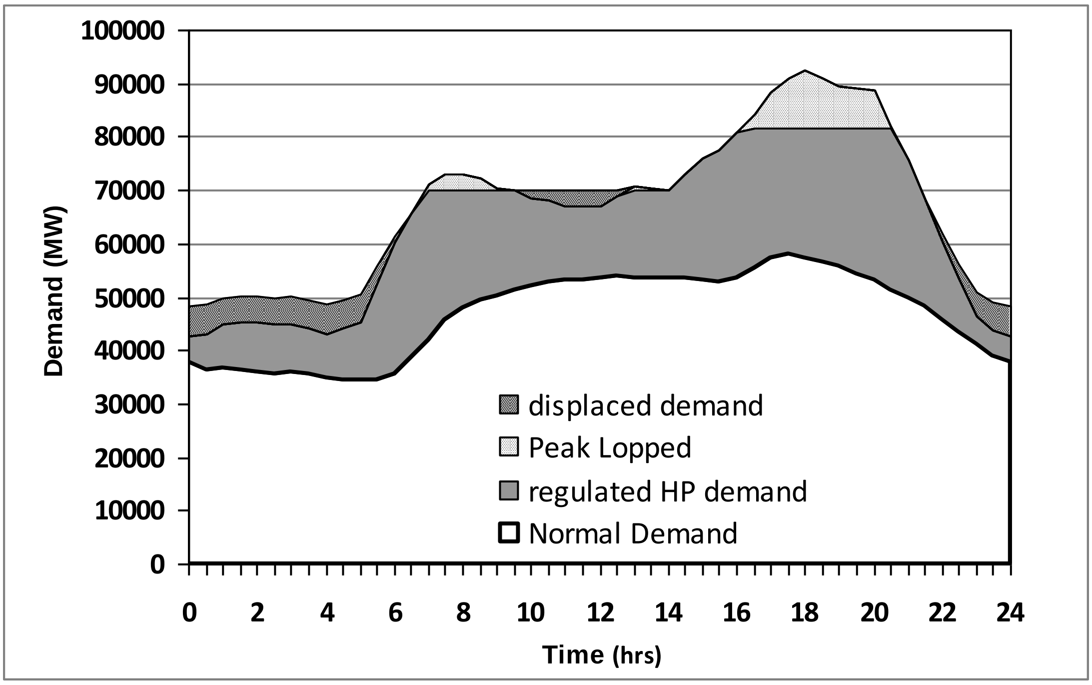

Fig. 8.4. A simulation of potential smoothing which might be achieved using additional overnight heat storage. A 25% uptake is assumed in the model.

Perhaps thermal stores with say 1 m^3 might be built into new buildings. These heat stores would be charged over night and then used either directly or as an enhanced heat source during peak time hours. Fig. 6.4 has been modelled assuming that 25% of the heat demand could be controlled by this mean. A reduction of 10000 MW on peak demand can be achieved. If a higher percentage of additional overnight heat store could be achieved then the smoothing would be greater.

8.5 Summary

It is clear that with widespread deployment of electric vehiclaes and/or heat pumps, serious consideration must be given to active management of demand through the use of more creative tariffs.

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)

= SMP + (VOLL - SMP)*LOLP
= £19.81 + (2400 - 19.81)*0.0005
= **£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)*SMP/***2*** +370*20.02/2
|
constrained on bid price
+ 270*19.23/***2*** + (42500-370+1080)*2400*0.0005/***2***

| |
constrained off bid   capacity payment

The factor 2 refers to half an hour

Total cote =
£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	