# CHAPTER 3

# Competition in Energy Supply

In this chapter the concept of competition in the energy sector is examined for both electricity and gas supply industries, and the experience of electricity deregulation in the UK and USA is discussed in detail. The potential role of demand-side management (DSM) is also investigated and comparisons are drawn between experiences in the UK and USA.

## 3.1 Introduction

It has traditionally been the case that gas and electricity utility companies, irrespective of ownership (i.e. state or privately owned), are natural monopolies, which are regulated by legislative measures. These monopolies evolved partly because of the high infrastructure costs associated with the transmission and distribution of gas and electricity, and partly because it was easier to manage and regulate utility companies which generated/supplied, transmitted and distributed electricity or gas. Indeed, it is difficult to imagine anything other than a monopoly, given that most buildings have only one physical connection to a gas pipe and another to an electricity cable. However, while monopolistic utility companies are relatively easy to control and regulate, they prevent competition in the energy market. Consequently, it is not possible to buy and sell 'bulk' energy in the same way other commodities are traded.

In recent years many governments around the world have begun to investigate alternative solutions which introduce competition into their respective electricity and gas supply industries. This has become possible because of various technical and financial advances made in the late 1980s and 1990s. The UK has been at the forefront in pioneering utility deregulation, and has completely restructured its utility sector. During the 1990s the UK deregulated first its electricity supply industry and then its gas industry, in a long and complex process, which at time of writing is still ongoing. Such has been the radical nature of these changes that in many ways the UK has become the 'pilot study' for the rest of the world. Following the UK's lead a number of countries, including the USA, have deregulated (at least in part) their electricity supply industries and are developing new energy-trading markets. In addition to the UK electricity spot market (i.e. the electricity 'pool'), four other 'pools' have so far been created in Europe; the Amsterdam Power Exchange (covering The Netherlands, Belgium and Germany), the Spanish Pool, the Swiss Pool and the Nordpool in Scandinavia (covering Norway, Sweden and Finland) [1].

## 3.2 The Concept of Competition

Consider the case of an organization which uses oil to heat its buildings. Under normal circumstances the organization will have a choice of competing fuel suppliers from whom to purchase oil. The organization can negotiate a bilateral supply contract with any one of these suppliers. If one supplier becomes too expensive, then the organization can simply switch to purchase oil from another supplier. If the general demand for fuel oil is high, then the suppliers will be able to raise their prices. Conversely, if demand is low then the price of oil will also be low. Thus a competitive market in fuel oil exists which reflects the demand for oil at any moment in time. As with any other commodity, the oil price will vary because customers have the ability to switch between suppliers. In addition, there is no cross-subsidy of one group of customers by another group of customers. Each fuel supply contract is negotiated on an individual basis between the parties concerned.

Now consider the same organization purchasing electricity under a tariff from a utility company. Since the electricity is supplied through cables owned by the utility company, the customer has no choice of alternative supplier and so the organization is compelled to purchase electricity at a price fixed by the utility company. As a consequence:

- *No competition exists*: The customer is in a weak position since electricity prices are fixed by the utility company.
- *No market exists*: Under a tariff, electricity prices are fixed, with the result that prices do not accurately reflect the fluctuations in demand for electricity. Although many tariffs do have reduced 'off-peak' elements, these are at best only a crude indicator of market demand.
- *The potential for cross-subsidy exists*: The utility company may decide to offer lower electricity prices to its large industrial customers, and recoup some of its

lost income by increasing the prices of its smaller domestic and commercial tariff customers. This is termed 'cross-subsidy', and effectively means that one group of customers is subsidizing another group.

While this monopolistic scenario may suit the utility companies, it does not benefit the customer. The utility companies are in a strong position and the potential exists for artificially high electricity prices. Lack of competition ultimately leads to:

- Manufacturing industry paying a high price for energy, with the result that the unit cost of production increases and the industry becomes less competitive.
- Utility companies becoming overmanned and inefficient.

It is therefore easy to see why many governments are reviewing the monopolistic position of their respective utility companies with a view to introducing a competitive energy market.

## 3.3 Competition in the Electricity Supply Industry

While it is easy to state that competition in the energy market is a desirable thing, in practice it is difficult to achieve a truly competitive market amongst utility companies. Utility networks, be they gas or electricity, lend themselves to monopolies and are not naturally suited to competition. This is because it is impractical and prohibitively expensive to construct two or more sets of competing transmission/distribution networks. Given this, the simplest and easiest way to organize affairs is to have a 'vertically integrated' structure in which a single utility company is responsible for provision of supply. Figure 3.1 shows the structure of a typical vertically integrated electricity supply industry.

In a vertically integrated electricity supply industry the various utility companies have monopolies over their 'franchise' regions. Within its franchise region a utility company will be responsible for generating, transmitting, distributing and supplying electricity to all its customers. Customers in the utility company's franchise region are forced to

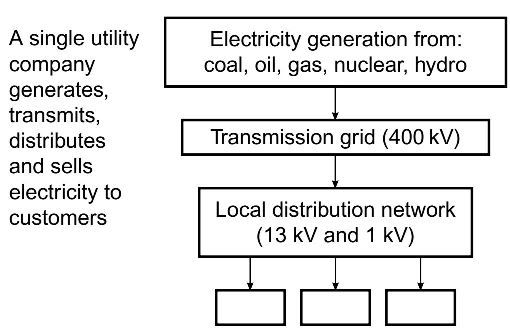


**FIG 3.1** A vertically integrated electricity supply industry.

purchase their electricity from the regional utility company. Vertically integrated utility companies can exist in both the private and the public sectors. Their monopolistic position is derived solely from their physical location, which excludes competition and means that the utility company has a protected market. Under this scenario energy prices can easily become overinflated if the utility company is not tightly regulated.

In order to promote competition in the electricity supply industry it is necessary to create a market for the commodity which is flexible and yet still robust enough to cope with wide fluctuations in demand. The market should:

- Allow various electricity supply companies and generators to compete with each other to sell electricity direct to customers.
- Allow customers to negotiate electricity supply contracts with various suppliers.
- Be transparent, so that generators, suppliers and customers can see that the market is fair and equitable.
- Create a 'spot market' which accurately reflects both demand for energy and cost of production. This spot market then becomes the market indicator of the real cost of production at any given point in time.
- Facilitate a future's market in electricity trading.

While the above points are relatively easy to achieve in a normal commodity market, they are not easily achieved in a market in which electricity is bought and sold. This is because electricity cannot be stored and must be generated only when it can be consumed. Any potential trading market in electricity must fully accommodate the physical constraints of an electricity supply system. As a result a truly competitive market in electricity is likely to be much more complex than a normal commodities market.

It is impossible to achieve a competitive market with a vertically integrated electricity supply industry. Instead a horizontally integrated structure is required. The introduction of a horizontally integrated electricity supply industry, in which the generation, transmission and distribution roles are all split up from each other, is the key to facilitating competition. By splitting up the roles it is possible to create competition between generators, who then have to bid in a 'spot market' for the right to supply electricity to the transmission grid. If the transmission company acts in a fair and independent manner, purchasing power at 'least cost', then any possible cartel should be eliminated. It then becomes possible for new 'independent power producers' to enter the market to compete with existing generators. This should result in a reduced cost to the customer for each unit of electrical energy produced. Figure 3.2 shows the structure of a typical horizontally integrated electricity supply industry.

Whilst the spot market described above facilitates competition between generators, it does not of itself offer the customer a choice of competing suppliers. In order to achieve this, the customer must be allowed to negotiate supply contracts with individual energy suppliers. This is achieved by allowing 'second tier' electricity 'wholesale' suppliers to purchase 'bulk' electricity from the transmission grid and sell it directly to customers. Under this arrangement the customer purchases electricity from competing supply companies, who pay a fee to the relevant distribution companies for the use of their 'wires'. This 'line rental' fee is then passed on to the customer and included in the

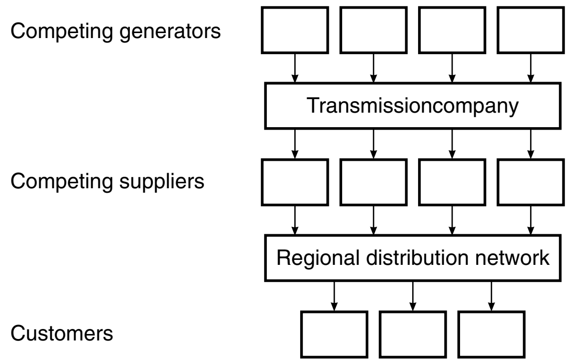


**FIG 3.2** A horizontally integrated electricity supply industry.

unit price paid for the electricity. In order to ensure that true competition takes place, the 'line rental' fees should be transparent and equal for all potential electricity suppliers. These fees are usually fixed by some form of statutory regulatory mechanism.

This discussion indicates that facilitating competition in an electricity supply industry involves the setting-up of a complex structure, with many demarcation boundaries. Indeed, there is an inherent conflict of interests between the engineering and financial requirements of a horizontally integrated structure. The transmission company is primarily interested in procuring enough electrical energy from generators in order to meet the instantaneous demand on its grid. It seeks to procure this energy from the cheapest power producers and is not particularly interested in individual supply contracts. Conversely, customers, suppliers and generators are primarily interested in negotiating contracts which ensure secure supply and therefore are not interested in the transmission company's need to meet instantaneous demand. Satisfying these conflicting needs requires the setting-up of complex bidding, pricing and settlement mechanisms. It is the specific nature of these mechanisms and the efficiency with which they are applied which will ultimately determine the success or failure of any electricity market.

In addition to the complex financial and settlement mechanisms required to operate the market, suppliers need to know the 'real-time' electricity consumption of their contract (i.e. non-domestic) customers. This involves the installation of 'smart' meters which measure electricity usage every half hour, and can be read remotely and automatically. The data from these meters are transmitted to remote disseminated centres, from which relevant data are sent to all the parties involved in the supply contract. Contract customers may purchase or lease their metering equipment, but the installation and maintenance of these meters should be carried out by approved operators.

## 3.4 The UK Electricity Experience

Competition in electricity supply is still in its infancy and many protocols are not yet firmly in place. Most of the electricity power markets which exist around the world are only a few years old and even the UK market, established in 1990, is still undergoing major revisions. This makes it difficult to describe general rules which apply to all electricity markets. In the absence of any firm 'ground rules' it is worthwhile looking in detail at the evolution of the competitive electricity market in England and Wales (the largest part of the UK), since this has been the 'template' for subsequent deregulation schemes in various parts of the world.

In 1990 in England and Wales a daily spot market known as the electricity 'pool' was created. The pool was administered by the National Grid Company (NGC), which owned and operated the transmission grid in England and Wales. Each morning the competing generating companies would submit 'bids' for their various generating sets to NGC for the following day's operation. Each bid included an offer price at which the generating company would be prepared to operate its various generating units for the following day. It also included a declaration of availability of generating plant for the following day. Once the generators had submitted their bids to the pool, the NGC examined its own demand forecast for the following day and ranked each generating unit in order of price (lowest price first), so that finally a merit schedule was produced. This schedule was then published at approximately 15.00 hours, so that the generating companies were notified of the generating units required for the following day. As there was often considerable overcapacity in the system, any generating units for which the offer price was too high were either placed on standby or excluded from the pool and forced to shut down.

As electricity cannot be stored, it is essential that the controllers of the national transmission grid be able to bring online (or download) additional generating capacity at very short notice to cope with fluctuating demand. Figure 3.3 shows the national grid demand profile for a peak 'winter time' weekday, 29 November 1993 [2]. This graph

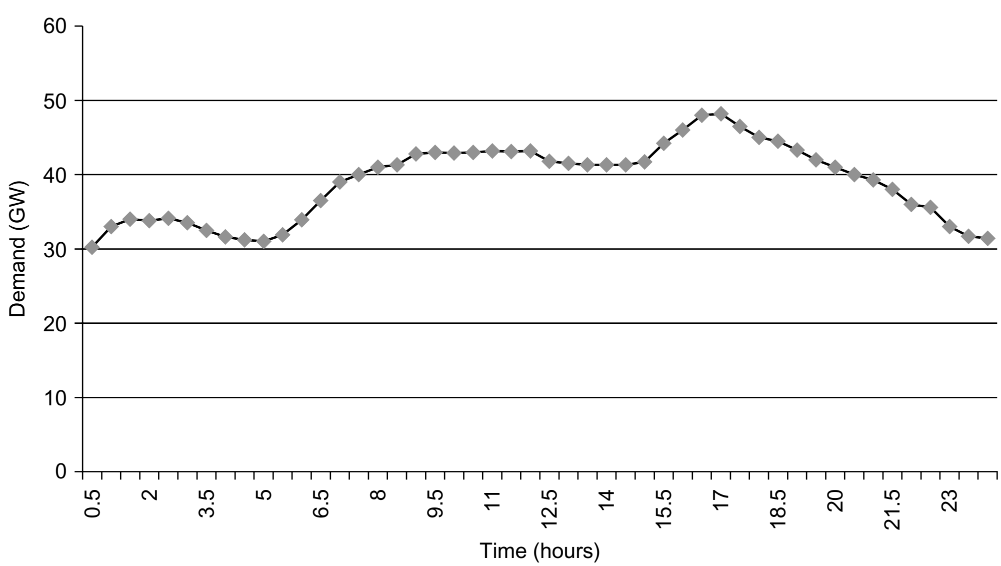


**FIG 3.3** Demand experienced by National Grid, 29 November 1993 [2].

shows that demand on that day varied considerably over the 24-hour period. To cope with increases in demand, generating units had to be brought online as and when they were required, but in strict accordance with their ranking in the daily pool merit schedule. In other words, generating sets which bid a low price were brought online first, while the more expensive units had to wait until demand increases before they were allowed to generate. Consequently the pool price varied for each half hour period throughout the day. When demand was high, it generally followed that pool price would also be high. In this way the pool price reflected the demand on the transmission grid.

The bid price submitted for the most expensive generating unit brought online to meet the demand in any given half hour period was known as the 'system marginal price' (SMP). For example, if the highest bid price accepted into the pool for the half hour period 11.00–11.30 hours was 2.5p/kWh, then the SMP would be 2.5p/kWh. It is important to note that it is the SMP, not the bid prices submitted by the individual generators, which became the basis for the eventual pool price for any given half hour, and that all the generators online in that particular half hour were paid the 'pool purchase price' (PPP). Electricity supply companies and large consumers purchasing from the pool had to pay the 'pool selling price' (PSP). Not surprisingly PSP is always greater than PPP, the difference being an uplift to cover the pool operating costs. The electricity pool in England and Wales enabled a competitive market to exist amongst the generators, and gave the market as a whole an indication of the true costs of electricity production at any given time.

While an electricity pool facilitates competition between the various generators, it does not on its own provide the mechanism for promoting a competitive market amongst customers. In order to achieve this, 'second tier' electricity 'wholesale' supply companies must be allowed to purchase electricity from the transmission grid and sell it on directly to customers. These wholesale suppliers negotiate bilateral contracts with the generating companies to purchase 'bulk' electricity at fixed rates, under a series of *contracts for differences* (defined later in this paragraph), and then sell it on to the customer at a marked-up price. These supply companies make their money by purchasing 'bulk' electricity from the generators at a low price and selling it on to their customers at a higher price. This involves considerable financial risk and the supply companies must negotiate contracts which ensure that they make a profit. However, pool price can be extremely volatile, especially in the winter. This volatility increases the element of risk for the supply companies if they purchase from the pool, with the result that they may lose money if they purchase at a high price and have to sell at a low one. The inherent volatility of the pool also makes planning ahead difficult. In an attempt to hedge against the risk of high pool prices, the supply companies take out *contracts for differences* with the individual generating companies. The contracts between the supply companies and the generators operate outside the pool and operate in a similar way to 'futures contracts' traded in the world's commodity markets. Under a typical contract for differences a supply company would contract with a specific generator to buy electricity at a fixed price for a specific time period (usually on a daily five time block basis) [3]. This 'hedges' against the volatility of the pool, and enables both generators and suppliers to predict the future financial risk involved in generating and selling electricity with some degree of confidence. These *contracts for differences* underpin the electricity market. They are called *contracts for differences* because payments are made by the parties involved to make good the difference between the pool price and the agreed contract price. Under this system, if the pool price falls below the contract price, the supply company remunerates the generator for the difference between the two prices, and vice versa if the pool price is above the contract price. The price of most of the electricity bought and sold is fixed in advance by *contracts for differences*. Hence the vast majority of electricity that is traded in England and Wales is purchased outside of the electricity pool.

### 3.4.1 The Evolution of the UK Electricity Market

The electricity pool described in Section 3.4 has become the basis for a number of other trading pools set up during the 1990s in Europe. However, in the UK, during the late 1990s, concerns were expressed that the pool system:

- Favoured the large generating companies; indeed there was suspicion that these companies were able in some way to control the pool price.
- Inhibited the introduction of new independent energy traders into the market.
- Inhibited the negotiation of bilateral electricity supply contracts between various parties.

The last point is an important one. In most trading deals the customer can state the price at which they wish to purchase a commodity and this has an influence on the overall market price. However, under the pool system the 'market price' (i.e. the pool price) was wholly determined by the sellers (i.e. the generating companies). The pool could therefore be viewed as being in some way only 'half a market' [4].

As a result of the concerns stated above, the UK completely restructured its electricity trading arrangements in 2000 and introduced the 'New Electricity Trading Arrangement' (NETA) [5]. This new arrangement abolished the old centrally regulated pool in favour of a 'free-market' approach which allowed a series of 'power exchanges' (i.e. electricity commodity markets) to be established; the hope being that the exchanges and brokers would create forwards, futures, and short-term bilateral markets. The intention was that the true price of electricity would become established through the power exchanges in much the same way that the commodity markets fix the price of other traded commodities. However, while the power exchanges can facilitate trade in 'bulk' energy, there is no way in which they can satisfy the physical engineering requirements of NGC (the operators of the transmission grid), who need to predict accurately at any point in time the demand on their network. Because electricity cannot be stored, the NGC must bring online more generating capacity as demand rises, otherwise power cuts will occur. Clearly, no commodity market can solve this problem alone! So the NETA arrangements were designed to operate in parallel with the new power exchanges, so that every time a bilateral contract is signed between a generator and a supplier they are required to inform NGC (or its settlements agent) of the quantity of electricity traded and the duration of the contract. It should be noted that parties are not required to notify NGC of the price paid for the electricity. All the supply companies and the generating companies are also required to notify NGC in advance of their expected operating levels for the following day. So by 11.00 hours on the day before trading, both the generators and the suppliers must submit to NGC their forecasts of demand, on a minute-by-minute basis, for the day ahead. They can do this because all parties know the quantity of electricity they have contracted to supply or purchase for the following day. By 'gate closure' (i.e. 3.5 hours before real time) the suppliers and generators must submit finalized demand forecasts to NGC. In this way NGC can effectively manage the transmission grid and inform the individual generators of the generating plant that will be required for the following day.

In theory the demand profiles predicted by the supply companies should exactly match the generation profiles predicted by the generating companies. In reality this never happens because it is difficult to accurately predict demand for electricity on a daily basis. A large number of factors influence electricity consumption, including weather and television scheduling. Since many variables influence electricity consumption, it is inevitable that the true demand for electricity will vary from the demand predicted by the supply companies. This means that NGC will have to bring online (or take offline) at short notice, additional generating plant in order to cope with variations from the predicted values. This of course incurs additional expense on behalf of the generating companies who have either to bring online extra plant or lay off generating plant which it had planned to operate. These 'imbalance costs' (i.e. costs incurred due to deviations from bilateral supply contracts) are calculated by NGC through a complex series of counter 'bids' and 'offers' made by both the generators and the suppliers. In this way NETA determines only the unit price of electricity which is 'traded' at the margins (i.e. outside of the power exchanges). It is intended that the 'imbalance' electricity costs will be higher than the 'bulk' electricity price, thus encouraging both the generators and the suppliers accurately to forecast predicted demand.

From the discussion above it is evident that in order to accommodate the engineering constraints of a transmission grid and facilitate a commodity market in electricity, extremely complex trading arrangements must be set up. Given this, it is understandable that competition in the electricity supply sector has been slow to evolve. Indeed, it would have been impossible without recent rapid advances in information technology (IT) in general and the Internet in particular. Without these IT advances, it would be impossible to rapidly transfer the large amounts of data associated with the bidding process to the many parties involved in a power exchange.

### 3.4.2 The Californian Experience

From the discussion in Section 3.4.1, it is clear that facilitating a true competitive market in electricity is an extremely complex process. Indeed, the electricity supply industry is of such strategic importance that if the deregulation process goes wrong, it can have a catastrophic effect on the whole economy. With this in mind, the experience of the Californian electricity supply industry should be a salutary lesson to all legislators who might be considering deregulating their utility sector. In January 2001, large parts of the state of California suffered major power cuts, not because of any technical failures, but as a direct result of poorly thought out legislation [6].

In 1996, the California Assembly voted to deregulate the state's electricity supply industry and to dismantle what was considered to be a government-regulated monopoly [7]. Prior to deregulation, the state had a vertically integrated electricity supply industry, with a number of investor-owned utility companies owning and operating their own power stations, transmission grids and distribution networks. With deregulation, a non-profit making organization, the California Power Exchange, was established and the following changes were made:

- Operational control of the transmission grids was transferred to a single Independent System Operator who became responsible for the management of the system.
- The investor-owned utility companies, such as Southern California Edison and Pacific Gas and Electric, were forced to sell most of their power stations to other unregulated private companies. This forced the major utility companies to purchase wholesale electricity through the California Power Exchange.
- The California Power Exchange acted as a wholesale commodities market, through which all the state's electricity was bought and sold. An auction process therefore set the price of wholesale electric power.

The investor-owned utility companies did, however, retain ownership and control of their distribution networks.

By making these changes the California legislature created a classic model for a competitive, deregulated electricity supply industry. However, there were two critical factors which were to have a significant influence on the events that were to follow:

1. While deregulation forced the utility companies to purchase their power on the open market and pay market prices, it prevented them from passing on any increases in the cost of wholesale electricity to their customers until at least 31 March 2002 [7].
2. Because of environmental concerns the state authorities prevented the building of new power stations. For 20 years or more, there had been no significant increase in California's generating capacity, despite the fact that demand for electricity in the state had been growing at approximately 2% each year [7].

These two critical factors were to have disastrous consequences for California in general and its electricity supply industry in particular. What the state legislature had done was to force the utility companies to buy wholesale electricity on the open market, which can be extremely volatile, while at the same time effectively fixing the price at which the utilities could sell electricity to their customers. The failings of this strategy were compounded by the fact that there was little excess generating capacity in the system. Without excess capacity there was little competitive pressure to keep wholesale prices low. As a result during the summer of 2000, when demand for power peaked, the utility companies urgently needed power from the electricity wholesalers and generating companies, who promptly raised their prices. Bulk electricity prices rose steeply, with the average price of electricity bought through the Power Exchange rising from approximately $30 per MWh in January 2000 to $330 in January 2001 [8]. In fact, in December 2000 the price reached a peak of $1400 per MWh [7]. Unable to recoup these inflated costs from their customers, the utility companies, not surprisingly, started to lose money. They rapidly ran out of money, with the two largest utilities, Southern California Edison and Pacific Gas and Electric, claiming that by January 2001 their combined losses exceeded $9 billion [7]. Indeed, Pacific Gas and Electric filed for bankruptcy in April 2001 [9]. The financial difficulties of the utility companies had two direct consequences:

1. The banks became very reluctant to lend more money to the cash-starved utility companies, who were rapidly becoming insolvent.
2. The wholesale and generating companies became reluctant to sell electricity to utility companies which were obviously in financial difficulties.

Faced with such high financial losses and not wanting to lose any more money, the utility companies took the only course of action available to them: they stopped purchasing electricity and the state of California suffered major power cuts. The state authorities then had to step in and try to pick up the pieces and sort the mess out.

The sorry state of affairs that occurred in California graphically highlights the major problems which can occur if all the issues involved in deregulation are not thought out in advance. Clearly, the combination of a shortage in generating capacity and an unregulated wholesale market, facilitating what is in effect an energy cartel, is a recipe for disaster.

## 3.5 Competition in the Gas Market

In many ways facilitating competition in the gas market is similar to the electricity market. As with electricity supply, horizontal integration is the key to a competitive gas market. However, there are a number of fundamental differences which make trading in natural gas much simpler than trading electricity:

- Natural gas is not generated; it is pumped out of oil and gas fields at sea or on land and sold to licensed shippers (i.e. wholesale supply companies) who sell it on to customers.
- Unlike electricity, natural gas can be stored to a limited extent.
- Demand for natural gas is very seasonal.

Given the differences between the nature of gas and electricity, a relatively simple horizontally integrated model is required to facilitate a competitive market in gas (as shown in Figure 3.4).

Because there are only three parties involved in the process and also because gas can be stored, the whole structure is much simpler to control and operate than that of an electricity supply industry. However, in order to ensure that the system functions in a fair and equitable manner it is important that the gas transmission company charges equal transportation fees to all suppliers and that all fees should be transparent.

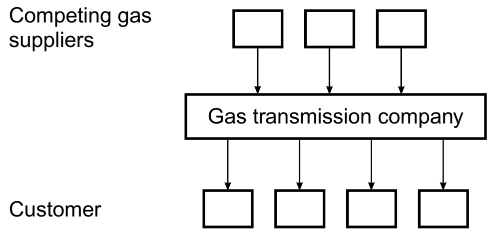


**FIG 3.4** Horizontally integrated gas supply industry.

Under a horizontally integrated gas supply structure, individual customers are free to negotiate bilateral supply contracts with various competing suppliers. The price paid by the customer is the price the supplier pays for the gas at the 'beachhead' plus the cost of transportation plus the supplier's profit. However, the price paid by the customer is mainly affected by the cost of gas at the beachhead.

It is the responsibility of the gas transmission company to balance supply and demand on its network on a continual basis. If too much gas enters the network then it must be stored in underground caverns or gasometers. Conversely, if too little enters the network, then gas from the storage vessels will have to be utilized. Suppliers therefore have to ensure that the gas they put into the network is roughly equal to the gas that their customers use. If they miscalculate either way by too great a margin, then the transmission company will levy a penalty charge on them.

# 3.6 Load Management of Electricity

From the discussions in Section 3.4 it can be seen that the 'true' cost of electricity production varies with demand on the network, and that through the use of pricing mechanisms such as the 'pool' it is possible to introduce real-time electricity pricing. Under this scenario *when electricity is consumed* becomes as important as *how much electricity is consumed*. Those customers who have the ability to manage their electrical load should thus be in a good position to reduce energy costs.

An ability to manage electrical load not only reduces customers' electrical costs, it also enables them to negotiate more competitive electricity supply contracts. If a potential customer wishes to negotiate a supply contract, they will need to furnish potential suppliers with the following information:

- The annual consumption of electricity in kWh.
- The maximum demand in kW.
- The load factor.

The load factor for any given period represents the percentage of time for which plant and equipment operates during that period. It can be calculated as follows:

$$\text{Load factor} = \frac{\text{Energy consumed (kWh)}}{\text{Max. demand (kW)} \times \text{Time period (h)}} \times 100$$

**TABLE 3.1** Typical load factors for a variety of applications [10]

| Type of organization | Load factor |
|---|---|
| 24-hour operation | 0.7–0.85 |
| Two shift system | 0.45–0.6 |
| Single shift system | 0.25–0.4 |
| Modern hotel complex | 0.5–0.6 |
| Hospital | 0.6–0.75 |
| Retailing | 0.3–0.4 |
| Catering business | 0.3–0.5 |

Table 3.1 shows some typical load factors which might be expected for a various types of organizations [10]. Buildings such as air-conditioned commercial offices, with a high daytime peak and a low night-time demand, will exhibit a low (i.e. poor) load factor. At the other extreme, factories which operate a 24-hour shift system will exhibit a high (i.e. good) load factor.

From the utility companies' point of view, organizations which possess a high load factor are potentially more desirable customers, since they will be buying more electrical energy for a given amount of investment in generation and distribution equipment. Customers who possess high load factors should therefore expect to negotiate better supply contracts than those with low load factors. This provides great potential benefit to contract customers who possess the ability to load shift from day to night by using technologies such as ice thermal storage (see Chapter 13). This should be particularly true for office buildings which would otherwise exhibit a very poor load factor.

## 3.7 Supply Side and Demand Side

The collective term for the operations performed by utility companies is the 'supply side', whereas energy consumption by customers is referred to as the 'demand side'; so named because customers create a demand for energy which is then supplied by utility companies. These concepts are illustrated in Figure 3.5.

Consider the case of an electricity utility company which experiences an overload of its system during the daytime in the winter months. The company cannot meet the increase in demand with its existing generating plant and is therefore faced with the choice of either building more power stations or encouraging its customers to consume less electricity and thus reduce electrical demand during the daytime. The former solution is a 'supply-side measure' since the solution lies wholly with the utility company (i.e. on the supply side) and the latter is termed a 'demand-side measure' since the solution to the problem lies with the customer. The demand-side solution could be achieved by introducing an electricity tariff offering lower unit charges to customers who are prepared to switch their electricity consumption from the daytime to the night-time. Through management of the 'demand side' in this way it is possible for utility

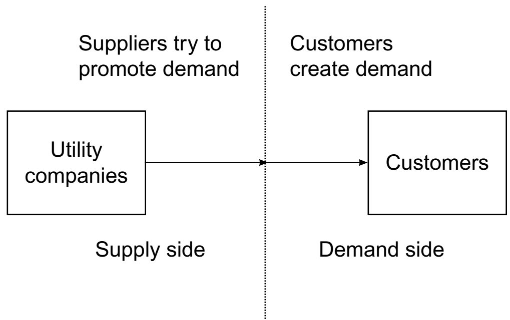


**FIG 3.5** Concept of supply side and demand side.

companies to utilize their resources efficiently and thus achieve substantial cost savings. Demand-side measures are therefore concerned with direct intervention in the customer's end use of electricity by the utility company, in a way which affects the planning of the utility company's infrastructure.

Traditionally electricity utility companies have tended to rely on supply-side measures to shape their businesses; that is, the utility companies have tried to influence the way in which their customers use electricity from the supply side of the meter, and have provided the infrastructure to meet the predicted demand. However, in recent years, both in the UK and the USA, there has been increasing interest in the use of demand-side measures.

## 3.8 Demand-Side Management

The concept of DSM (sometimes referred to as 'least cost planning') was pioneered in the USA during the 1980s, where it has since become an influential force. In some parts of the USA the electrical demand can increase by as much as 40% during the summer months, due to the use of air-conditioning equipment [11]. There is also stiff legislative opposition from the Public Utility Commissioners to the construction of new power stations. Faced with this situation many utility companies in the USA have introduced DSM programmes to encourage customers to conserve energy, and persuade as many as possible to shift their daytime load to the night-time. In the USA, DSM programmes include such measures as financial support for feasibility studies, free advice on techniques, capital grants towards the cost of new equipment and even the free issue to customers of low energy light bulbs. Many utility companies in the USA have found it more economical to persuade their customers to conserve energy, rather than be forced to build new generating plant. A typical example of this is that of Pacific Gas and Electricity, which in 1985 announced that it intended to 'build' a new power plant; a 1000 MW conservation power plant. In other words they intended to buy extra efficiency improvements which would reduce their peak demand by 1000 MW [12].

Simple analysis of energy consumption demonstrates the great benefit of encouraging energy conservation over the construction of new generating plant. If it assumed that a typical thermal power station has an efficiency of 35%, then the overall primary energy saved through the conservation of 1 kWh of delivered electrical energy is:

$$\text{Primary energy saved} = \frac{1}{0.35} = 2.86 \text{ kWh}$$

From this it is obvious that in energy conservation terms, encouraging customers to conserve electrical energy makes much sense. Nevertheless, in order to persuade the utility companies to adopt an energy conservation strategy, it must also make commercial sense. In the late 1980s, Ontario Hydro of Canada estimated that meeting its peak demand obligations through supply-side measures (i.e. constructing new generating plant and reinforcing transmission and distribution networks) would cost the utility four times as much as using demand-side measures [13]. The findings of Ontario Hydro are backed up by Rosenfeld and de la Moriniere [14] who demonstrated in 1985 the cost of constructing new generating capacity to be in the region of \$1200–\$1500/kW, which compared very poorly with the maximum of \$400/kW of electricity saved which could be achieved by using an ice storage system. It is therefore clearly in the interests of vertically integrated utility companies, such as those that exist in many parts of the USA and Europe, to encourage the installation of DSM technologies. To this end, many of the utility companies in the USA offer substantial capital incentives to building users to install technologies such as low energy light fittings and ice thermal storage [12].

Although DSM has become an influential force in the USA, its country of origin, the UK has been slow to adopt it. The UK does not suffer from a shortage of generating capacity, as is the case in some parts of the USA. It also experiences a winter peak, unlike many states in the USA. In addition, in England and Wales the electricity supply industry is not vertically integrated as much of the USA still is, thus making comparisons between the two countries very difficult. However, despite the obvious differences between the electricity supply industries in the USA and England and Wales, the regional distribution companies in the UK have recently become interested in DSM, since it is one method by which they can significantly reduce the demand on their cables and transformers, and thus reduce their operating and capital investment costs.

Because of the complex nature of the UK's horizontally integrated electricity supply industry, the role of DSM in the UK is somewhat ambiguous. In theory the widespread introduction of DSM should:

- Produce a reduction in the fuel burnt at power stations.
- Cause the deferral of the capital and financing costs of new power station construction.
- Cause a reduction in distribution losses.
- Result in the possible deferral of distribution reinforcement.
- Cause a reduction in transmission losses.
- Result in the possible deferral of transmission reinforcement associated with both new power plants and increased loads.
- Lead to a reduction in the emissions of $CO_2$, $SO_2$ and $NO_2$ from power stations.

While at first sight all the above points seem to indicate that there is a strong case for implementing DSM policies in the UK, further analysis casts doubt on the validity of the statement above. In theory all parties in the UK electricity supply industry benefit from the introduction of DSM. Yet, because of the fragmentation of the industry due to horizontal integration it is difficult to initiate and coordinate an effective DSM policy. For example, who will pay for a DSM policy? Are the regional distribution companies going to pay for a policy which arguably gives greatest benefits to the generators and the NGC? It is also difficult for the competing generators to initiate DSM, since they have no 'captive' market and they have little direct influence over the end-users. Also, the structure of the electricity market is such that individual generators are always seeking to generate as much electricity as possible. The benefit to the generators through the implication of a DSM policy is dubious to say the least, since there is overcapacity in the system, and every generator benefits from higher electricity prices when demand is high. Therefore, for DSM to succeed in the UK it must benefit both the regional distribution companies and their customers.

### 3.8.1 The USA Experience

The US-based energy research body the Electrical Power Research Institute (EPRI) defines DSM as:

> *The planning, implementation and monitoring of utility activities designed to influence customer use of electricity in ways that will produce desired changes in load shape* [15]

In the USA, DSM programmes are often initiated by the Public Utility Commissioners who are intent on minimizing the construction of new generating plant. Utility companies are required to demonstrate to the Commissioners that their proposed course of action is the least expensive option for supplying customers with electricity. The onus is therefore on the utility companies to reduce demand rather than build more power stations. In some states in the USA, utilities are even being awarded bonuses for implementing DSM programmes.

Although DSM programmes in the USA have been initiated as a result of social concern and regulatory pressure, it is the potential for profit to the utility companies that has driven such programmes. In the USA the utilities are permitted to over-recover the costs of DSM programmes through increases in electricity prices. Consequently, the utilities receive a greater marginal return from demand-side measures than they would from supply measures. This has resulted in DSM programmes in North America being used on a large scale. Many North American utility companies spend more than 5% of their total turnover on investment in DSM. Table 3.2 shows the investment levels and targeted energy savings for some DSM programmes, operated by a variety of North American utility companies [16].

Although some of the DSM programmes included in Table 3.2 have not proved to be cost effective, many of the utility companies have reported that their DSM programmes have proved less expensive in total cost terms, when compared with the costs avoided

**TABLE 3.2** Examples of North American utilities' expenditure on DSM [16]

| Utility company | Current expenditure ($ millions) | Target GWh savings | Target MW savings | MW savings as % of projected peak | Target year for savings |
|---|---|---|---|---|---|
| BC Hydro | 66 | 4491 | 1266 | 9.4 | 2000 |
| Hydro Quebec | 251 | 9289 | 5065 | 13.2 | 2000 |
| Manitoba Hydro | 8 | 931 | 255 | 4.7 | 2000 |
| Ontario Hydro | 377 | 14,911 | 5200 | 16.0 | 2000 |
| Consolid. Edison | 76 | 7120 | 2500 | 22.5 | 2008 |
| Florida P & L | 66 | 2800 | 1884 | 8.7 | 1999 |
| Long Island | 33 | 2840 | 589 | 11.4 | 2008 |
| Nevada Power | 5 | 190 | 147 | 5.2 | 2007 |
| New York State | 25 | 2790 | 846 | 18.9 | 2004 |
| Niagara Mohawk | 37 | 2680 | 849 | 12 | 2008 |
| Orange & Rock. | 8 | 191 | 122 | 7.6 | 2008 |
| Pacific G & E | 120 | 5760 | 2270 | 11.1 | 2001 |
| Rochester G & E | 7 | 876 | 186 | 10.7 | 2009 |
| Southern Calif. | 107 | 5170 | 2780 | 11.2 | 2009 |
| Wisconsin Elec. | 40 | 1260 | 290 | 5.6 | 2000 |

on the supply side. These findings even applied in circumstances where the utility company had an excess of generating capacity.

When a DSM policy is introduced a utility company avoids generating costs, network losses, some administration charges, and may avoid capital expenditure on network reinforcement and expanding generating capacity. However, it also sells less electricity and is therefore liable to a loss of revenue through implementing a DSM programme.

To avoid this situation some form of 'balancing' mechanism must be provided to ensure that the utility company does not lose revenue. In the USA, this balancing mechanism is provided by a regulator, who approves an increase in tariffs for all customers, subject to the utility company demonstrating that the 'average' customer receives an overall reduction in energy costs [17].

In recent years the electricity supply industry in the USA has undergone major restructuring in order to facilitate wholesale trading in electricity in a similar way to the industry in the UK [18]. Despite the uncertainty that surrounds this change, the industry in the USA reported that in 1999, a total of 848 electricity utilities had DSM programmes and of this number, 459 'large' DSM programmes resulted in a 50.6 billion kWh energy saving [19].

### 3.8.2 The UK Experience

Unlike North America, where DSM programmes have become commonplace, DSM in the UK is still in its infancy. Under the old state-owned electricity supply industry, one of the few examples of a DSM policy in the UK was the introduction of the 'Economy 7' tariffs which were used in conjunction with night storage heaters. Over many years under the nationalized regime, night storage heaters were heavily marketed, the main objective being:

- To achieve better utilization of the nation's generating plant.
- To utilize the electricity distribution network more efficiently.
- To raise useful revenue for the regional electricity boards by selling the night storage heaters to the public.

The marketing of night storage heaters was an extremely successful policy – perhaps too successful. Analysis of the pool price profile for an average weekday in December 1992 (see Figure 3.6) shows that the PSP for some of the night-time is actually greater than the daytime (office hours) price. This was because of the generating capacity required at night-time to satisfy night storage heaters. However, this high night-time PSP was not reflected in the price paid by tariff customers, typically between a third to a half of the daytime price, for both domestic 'Economy 7' customers and a commercial maximum demand tariff customers. In the case of 'Economy 7', the off-peak price was set to compete with gas central heating in the domestic market. As a result the users of night storage heaters were in fact being subsidized by other customers who have to pay higher daytime prices.

The intensive marketing of night storage heaters meant that in some areas of the UK, the regional distribution networks experienced high night-time peaks. This caused problems and resulted in a number of regional distribution companies (who were also electricity suppliers) marketing flexible off-peak domestic tariffs. These flexible off-peak tariffs were designed to replace the old monolithic 'Economy 7' tariff, and offered customers 10 hours of off-peak electricity compared with the old 7-hour period [20]. A sample of one of these flexible tariffs is shown in Table 3.3 from which can be seen that the utility company is trying to utilize more effectively the troughs

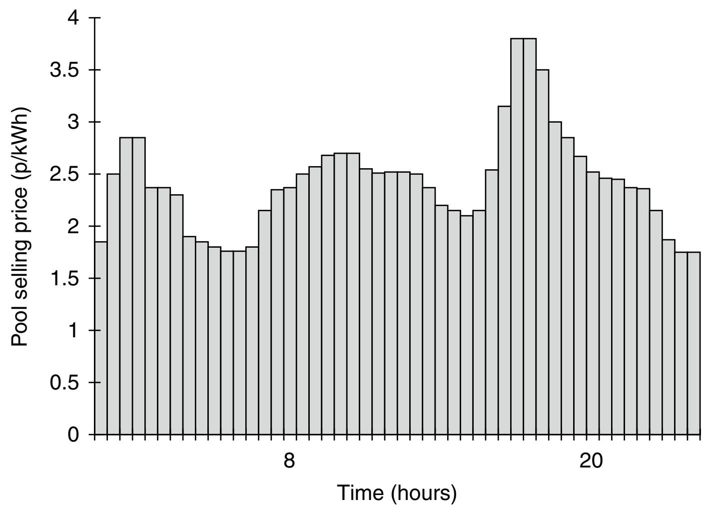


**FIG 3.6** Average weekday pool selling price, December 1992.

**TABLE 3.3** East Midlands electricity 'heatwise' tariff 1 May 1992 [20]

| Off-peak supply is available for 10 hours | Monday to Friday | Saturday and Sunday |
|---|---|---|
| Five hours continuously during night | 00.00–7.00 | 00.00–8.00 |
| Three hours continuously during afternoon | 13.00–16.30 | 13.00–17.30 |
| Two hours continuously during evening | 17.30–22.00 | 17.30–22.00 |
| Standing quarterly charge | £3.90 | |
| Unit charges: | | |
| Off-peak | 2.90p/kWh | |
| Peak | 7.64p/kWh | |

in the UK's daily demand profile, which generally correspond to periods when electricity prices are low.

To the regional distribution companies these flexible tariffs have a number of advantages. They shift much of the off-peak period from its 'traditional' night-time slot to the daytime and evening periods, so that troughs in the daytime demand can be exploited. They also have inherent flexibility which allows the utility company to control the precise start and stop times of the 'off-peak' periods and allows these to be varied from day to day.

The regional distribution companies receive two major benefits from these flexible tariffs:

1. They achieve better utilization of their distribution networks and avoid capital expenditure on network reinforcement.
2. If they are also a supply company, the regional distribution company can purchase electricity from the generators at periods when prices are low and sell it on to their customers for heating purposes at the standard tariff price. Consequently, they have more scope for increasing profit margins in their supply business.

To implement flexible tariffs such as the one outlined above involves the installation of complex metering equipment, which is capable of both recording the electricity consumption at the various periods of the day and also of receiving switching signals from the utility company concerned, to activate the 'off-peak' period on the meter. To achieve this in the domestic market the utility companies offering these tariffs have to use a radio tele-switching system.

If the subject of night storage heaters is set aside, DSM in the UK is being driven primarily by those regional distribution companies which are experiencing network problems [21,22]. The position of the generators towards DSM is ambivalent, since it is unclear how they would benefit commercially. Therefore, the potential benefits of DSM in the UK are perceived to lie in enabling the distribution companies to optimize their existing networks.

Electricity companies always seek to maximize their returns on their investment in generation, transmission and distribution equipment. In the past, increasing electricity demand has ensured that whenever a system needed reinforcement in order to maintain security of supply, the capital investment could be recouped from increased electricity sales. Before deregulation, the electricity supply industry used vigorously to promote the use of electricity in the hope of maximizing sales. This situation has, however, changed. The electricity market in the UK is a mature one. Sales of electricity have steadied and predicted growth is low. In some areas electricity sales are static or even declining. Distribution companies cannot look to increased sales to finance system reinforcement. Under this scenario DSM becomes an important option which the distribution companies must consider.

From the position of the competing generators in the UK, it is unlikely that DSM is going to gain much support. Electricity prices tend to be high when demand is high. Therefore all the generators benefit from high demand. From a generator's point of view, DSM can be viewed as a competitor since it reduces electricity sales.

DSM programmes cost money to implement, especially if they involve capital grants to customers to purchase energy efficient or load shifting equipment. Therefore the utility companies need some mechanism to recoup investment costs. In the USA, utility companies are allowed to increase tariff prices to all their customers to pay for DSM programmes. In effect the ordinary customers of the utility companies are subsidizing those customers benefiting from the DSM measure. In the UK the regulatory authorities will not allow this approach to paying for DSM, since it both distorts the market and is 'unfair' on franchise customers. Indeed, the regulatory authorities in the UK appear to be opposed to the widespread adoption of such schemes on the grounds that they represent a cross-subsidy between customers. The distribution companies must therefore recoup their DSM programme costs from those customers who benefit directly from it.

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