Chapter 3

Understanding Energy Bills

3.0 INTRODUCTION

Although temporary increases in energy supplies may cause short-term rate decreases or rate stability, the long-term prospect is for energy costs to continue to increase. This is particularly true in the case of electric power where the costs are associated as much with the cost of building the new generation facilities as with the cost of producing the electricity. The impact of an increase in energy costs can be easily seen by examining the rate schedules for the various fuel sources, yet few managers take the time to peruse and understand their utility's billing procedures.

Why? The reasons are many, but the main ones seem to be the following:

- Rate schedules are sometimes very complicated. They are difficult to understand, and the explanations developed by state utility regulatory boards and by the utilities themselves often confuse the customer rather than clarify the bill.

- Energy is too often treated as an overhead item. Even though energy is frequently a substantial component of a product's cost, the cost of the energy is almost always included as an overhead item rather than a direct cost. This makes the energy cost more difficult to account for and control. Consequently, management does not give energy costs the attention they deserve.

This must change and, in fact, is changing. More and more managers are trying to understand their rate schedules, and sometimes they even participate in utility rate increase hearings.

Managers should know what electric rate schedule they are under and how much they are charged for the various components of their electric bill: demand, consumption, power factor, sales tax, etc. They should also know the details of their other energy rate structures. This chapter covers rate schedules for the major energy sources utilized in this country. While the majority of the discussion focuses on electricity, attention is also given to gas, fuel oil, coal, and steam/chilled water.

3.1 ELECTRIC RATE STRUCTURES

3.1.1 Utility Costs

Perhaps the best way to understand electric utility billing is to examine the costs faced by the utility. The major utility cost categories are the following:

- *Physical Plant.* This is often the single biggest cost category. Because electric power plants have become larger and more technologically sophisticated with more pollution control requirements, the cost of building and operating an electric power generation facility continues to increase. Furthermore, the utility is required to have sufficient capacity to supply the peak needs of its customers while maintaining some equipment in reserve in case of equipment failures. Otherwise brownouts or even blackouts may occur. This added capacity can be provided with expensive new generating facilities. Alternatively, instead of building new facilities, many utilities are urging their customers to reduce their peak demand so that the existing facilities will provide sufficient capacity.

- *Transmission lines.* Another major cost category is the cost of transmission lines to carry the electricity from where it is produced to the general area where it is needed. Electricity is transmitted at relatively high voltages—often 500 to 1,000 kilovolts—to minimize resistance (I^2R) losses. This loss can be large or small depending on the transmission distances involved.

- *Substations.* Once the electricity reaches the general area where it is needed, the voltages must be reduced to the lower levels which can be safely distributed to customers. This is done with step-down transformers at substations. A few customers may receive voltage at transmission levels, but the vast majority do not.

- *Distribution systems.* After the voltage is reduced at a substation, the electricity is delivered to the individual customers through a local distribution system typically at a voltage level around 12 kilovolts. Most residential customers are supplied electricity at 120 and 240 volts, single-phase. In addition to these two voltages, commercial customers often take 230-volt, three-phase service. Some larger customers must also have 480-volt, three-phase service in order to power their large motors, ovens, and process equipment. The desired voltages are provided through the use of appropriate step-down transformers at the customer's specific location. Components of the distribution system which contribute to the utility's costs include utility poles, lines, transformers, and capacitors.

- *Meters.* Meters form the interface between the utility company and customer. Although the meter costs are relatively small, they are considered a separate item by the utility and are usually included in the part of the bill called the customer charge. The cost of a meter can range from under $50 for a residential customer to $1500 or more for an industrial customer requiring information on consumption, demand and power factor.

- *Administrative.* Administrative costs include salaries for executives, middle management, technical and office staff, as well as for maintenance staff. Office space and office equipment, taxes, insurance, and maintenance equipment and vehicles are also part of the administrative costs.

- *Energy.* Once the generation, transmission and distribution systems are in place, some form of primary energy must be purchased to fuel the boilers and generate the electricity. In the case of hydroelectric plants, the turbine generators are run by water power and the primary energy costs are small. Fossil fuel electric plants have experienced dramatic fluctuations in fuel costs depending on how national and world events alter the availability of oil, gas, and coal. The cost of fuel for nuclear power plants is reasonable, but the costs of disposing of the radioactive spent fuel rods, while still unknown, are expected to be relatively large.

- *Interest on debt.* This cost category can be quite large. For example, the interest on debt for a large power plant costing $500 million to $1 billion is substantial. Utilities commonly sell bonds to generate capital, and these bonds represent debt that the company must pay interest on.

- *Profit.* Finally the utility must generate enough additional revenue above costs to provide a reasonable profit to stockholders. The profit level for private utility companies is determined by the state utility regulatory commission and is called the *rate of return*. Public-owned utilities such as municipal utilities or rural electric cooperatives usually set their own rates and their profit goes back to their customers in the form of reduced municipal taxes or customer rebates.

Once you understand what costs contribute to an electric bill, the next step is to learn how these costs are allocated to the various customers. The *billing procedure*, also called the *rate schedule*, should be designed to reflect the true costs of generating the electric power. If the customers understand the problems faced by the utilities, they can help the utilities minimize these costs. Recent rate schedules and proposed new ones capture the true costs of generation much better than has been done in the past, but more changes are still needed.

3.1.2 Regulatory Agencies

Private electric and gas utilities are chartered and regulated by individual states, and are also subject to some federal regulation. The state utility regulatory agencies are most often called Public Utility Commissions or Public Service Commissions. Private utilities are called *Investor Owned Utilities* (IOUs), and their retail rates for residential, commercial and industrial customers are subject to review and approval by the state utility regulatory agencies.

Utility rates are set in two steps: first, the revenue requirements to cover costs plus profit is determined; second, rates are designed and set to recover these costs or revenue requirements [1]. The state regulatory agencies set a *rate of return* for utilities. The rate of return is the level of profit a utility is allowed to make on its investment in producing and selling energy. In developing rates, the costs of serving different classes of customers must be determined and allocated to the customer classes. Rates are then structured to recover these costs from the appropriate customer class. Such rate designs are called *cost-based rates*. Often, these costs are *average*, or *embedded costs*, and do not consider the *marginal costs* associated with providing electricity at different times of the day and different seasons of the year. Rate design is subject to many competing viewpoints, and there are many different objectives possible in rate setting.

When an IOU requests a rate increase, the state regulatory agency holds a public hearing to review the proposed rate increase, and to take testimony from the utility staff, consulting engineers, customers and the public at large. The utility presents its case for why it needs a rate increase, and explains what its additional costs are. If these costs are judged "prudent" by the state regulatory agency and approved, the utility is allowed to recover the costs, plus adding some of that cost to its rate base—which is the accumulated capital cost of facilities purchased or installed to serve the customers and on which the utility can earn its rate of return.

Many large utility customers participate actively in the rate hearings for their utility. Some state regulatory agencies are very interested in comments from utility customers regarding quality of service, reliability, lengths of outages, and other utility service factors. State regulatory agencies vary greatly in their attitude toward utility rate increases. Some states favor the utilities and consider their interests to be first priority, while other states consider the interests of the customers and the public as paramount.

Two other major categories of utilities exist: *public* or *municipal utilities* owned and operated by cities and local government entities; and *Rural Electric Cooperatives* (RECs) established under the Rural Electrification Administration and operated by customer Boards of Directors. State regulatory agencies generally do not exercise the same degree of control over public utilities and RECs, since these utilities have citizens and customers controlling the rates and making the operating decisions, whereas the IOUs have stockholders making those decisions. Municipals and RECs also hold public hearings or public meetings whenever rate increases are contemplated. Customers who have an interest in participating in these meetings are usually encouraged to do so.

Interstate transactions involving the wholesale sale or purchase of electricity between utilities in different states are subject to regulation by the Federal Energy Regulatory Commission (FERC) in Washington, DC. FERC also regulates the designation of some cogenerators and renewable electric energy suppliers as Qualifying Facilities (QFs) or Small Power Producers (SPPs). Few retail customers outside of those engaged in self-generation would have any reason to participate in the regulatory process at this level. FERC also licenses non-federal hydroelectric facilities.

3.1.3 Customer Classes and Rate Schedules

An electric utility must serve several classes of customers. These classes vary in complexity of energy use, amount of consumption, and priority of need. The typical customer class categories are residential, commercial and industrial. Some utilities combine commercial and industrial customers into one class while other utilities divide the industrial class into heavy industrial and light industrial customers.

The state regulatory agencies and utilities develop different rate schedules for each customer class. Electric rate structures vary greatly from utility to utility, but they all have a series of common features. The most common components of rate schedules are described below, but not all of these components are included in the rate schedule for every customer class.

- *Administrative/Customer Charge:* This fee covers the utility's fixed cost of serving the customer including such costs as providing a meter, reading the meter, sending a bill, etc. This charge is a flat monthly fee per customer regardless of the number of kWh of electricity consumed.

- *Energy charge:* This charge covers the actual amount of electricity consumed measured in kilowatt-hours. The energy charge is based on an average cost, or base rate, for the fuel (natural gas, fuel oil, coal, etc.) consumed to produce each kWh of electricity. The energy charge also includes a charge for the utility's operating and maintenance expenses.

  Many utilities charge a constant rate for all energy used, and this is called a *flat rate* structure. A *declining block* approach may also be used. A declining block schedule charges one price for the first block of energy (kWh) used and less for the next increment(s) of energy as more energy is used. Another approach is the *increasing block* rate where more is charged per increment as the consumption level increases. Although this approach would tend to discourage electric energy waste, it does not meet the *cost-based rate* criterion and is therefore not widely used.

- *Fuel cost adjustment:* If the utility has to pay more than its expected cost for primary fuel, the increased cost is "passed on" to the customer through use of a prescribed formula for a fuel adjustment cost. In times of rapidly increasing fuel prices, the fuel adjustment cost can be a substantial proportion of the bill. This concept was adopted when fuel costs were escalating faster than utility commissions could grant rate increases. However, utilities can also use the fuel adjustment cost to reduce rates when fuel costs are lower than the cost included in the base rate.

- *Demand charge:* The demand charge is used to allocate the cost of the capital facilities which provide the electric service. The demand charge may be "hidden" in the energy charge or it may be a separate charge; for example it may be expressed as $6.25 per kW per month for all kW above 10 kW. For large customers, the demand charge is generally based on their kilowatt demand load. For smaller users such as residential and small commercial customers this charge is usually averaged into the energy charge. The demand charge is explained in more detail in Section 3.1.6.2.

Understanding the difference between *electric demand*, or power in kilowatts (kW), and *electric energy*, or consumption in kilowatt-hours (kWh), will help you understand how electric bills are computed. A helpful analogy is to think of an automobile where the speedometer measures the rate of travel in miles per hour, and the odometer measures the total miles traveled. In this instance, speed is analogous to electric power, and miles traveled is analogous to total energy consumed. In analytical terms, *power is the rate of use of electric energy*, and conversely, *energy is the time integral of the power*. Finally, the value of the power or demand a utility uses to compute an electric bill is obtained from a peak power measurement that is averaged over a short period of time. Typical averaging times used by various electric utilities are 15 minutes, 30 minutes and one hour. The averaging time prevents unreasonable charges from occurring because of very short, transient peaks in power consumption. Demand is measured by a demand meter.

- *Demand ratchet:* An industrial or commercial rate structure may also have a demand ratchet component. This component allows the utility to adequately charge a customer for creating a large kilowatt demand in only a few months of the year. Under the demand ratchet, a customer will not necessarily be charged for the actual demand for a given month. Instead the customer will be charged a percentage of the largest kW value during the last 11 months, or the current month's demand, whichever is higher.

- *Power factor:* If a large customer has a poor power factor, the utility may impose another charge, assessed as a function of that power factor. Power factor is discussed in detail in section 3.1.6.4.

All of these factors are considered when a utility sets its *base rates*—the rates the utility must charge to recover its general cost of doing business. The term "base rates" should not be confused with the term "rate base" which was previously defined. The base rates contain an energy charge that is estimated to cover the average cost of fuel in the future. The fuel adjustment charge keeps the utility from losing money when the price of their purchased primary fuel is higher than was estimated in their base rates.

Figure 3-1 presents a generalized breakdown of these rate components by customer class.

In addition, there are also a number of other features of electric rates incorporated in the *rate structure* which includes the relationship and form of prices within particular customer classes. The rate structure is set to maintain equity between and within customer classes, ensuring that there is no discrimination against or preferential treatment of any particular customer group. Some of the factors considered in the rate structure are: season of use; time of use; quantity of energy used—and whether increased consumption is encouraged, discouraged, or considered neutral; and social aspects such as the desire for a "lifeline" rate for low-income or elderly customers. A number of these factors are illustrated in the description of the specific rate structures shown in examples for particular customer classes.

3.1.4 Residential Rate Schedules

As shown in Figure 3-1, there are many residential users, but each is a relatively small consumer. A typical residential bill includes an administrative/customer charge, an energy charge which is large enough to cover both the actual energy charge and an implicit demand charge, and a fuel adjustment charge. Residential rates do not usually include an explicit demand charge because the individual demand is relatively inconsequential and expensive to meter.

3.1.4.1 Standard residential rate schedule

Figure 3-2 presents a typical monthly rate schedule for a residential customer.

3.1.4.2 Low-use residential rate schedule

A typical low-use residential service rate is shown in Figure 3-3. This schedule, which is an attempt to meet the needs of those on fixed incomes, is used for customers whose monthly consumption never exceeds 500 kWh. In addition, it cannot exceed 400 kWh more than twice a year. This rate is sometimes referred to as a *lifeline rate*.

3.1.4.3 Residential rate schedules to control peak uses

Although individual residential demand is small, collectively residential users place a peak demand burden on the utility system because the majority of them use their electricity at the same times of the day during the same months of the year. Some utilities charge more for energy during peaking months in an attempt to solve this problem. Many utilities

Customer Class	Comments	Typical schedule bills for: Consumption (kWh)	Demand (kW)	Power factor (kVAR)
1. Residential	Small user but large numbers of them	√		
2. Commercial	Small to moderate user; relatively large numbers	√		
3. Small industrial	Small to moderate user; fewer customers	√	√	
4. Large industrial	Large user with low priority; typically, only a few customers in this class, but they consume a large percentage of the electricity produced.	√	√	√

Figure 3-1.
Generalized breakdown of electric rate schedule components.

Customer charge:	\$8.00/month
Energy Charge:	All kWh @ 6.972 ¢/kWh
Fuel adjustment:	(A formula is provided by the utility to calculate the fuel adjustment charge each month. It is rather complex and will not be covered here.)

Figure 3-2. Typical residential rate schedule.

Customer charge:	\$5.45/month
Energy Charge:	5.865 ¢/kWh
Fuel adjustment:	(A formula is provided for calculating this charge.)

Figure 3-3. Low-use residential schedule.
(Courtesy of Oklahoma Gas and Electric Company)

have an optional *time-of-day* or *time-of-use* rate which is supposed to help alleviate the daily peaking problem by charging customers more for electric use during these peak periods. A number of utilities also have a load management program to control customers' appliances.

Figure 3-4 provides examples of a Florida utility's residential demand profile over a given 24-hour period during the weekdays. Figure 3-4 (a) shows the residential winter peak demand profile. This utility experiences one large peak around 9:00 a.m. and another somewhat smaller

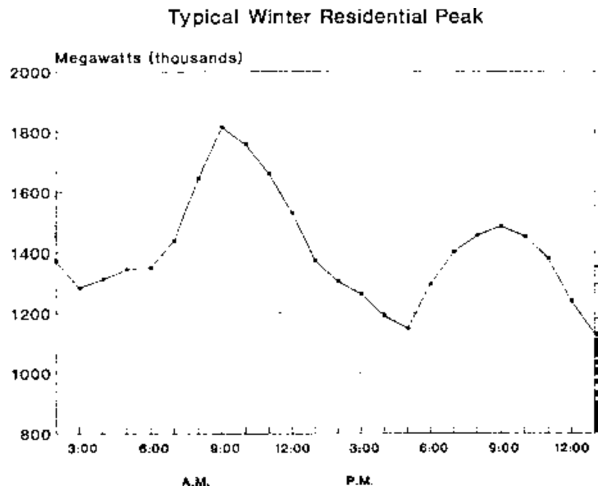


Figure 3-4 (a)

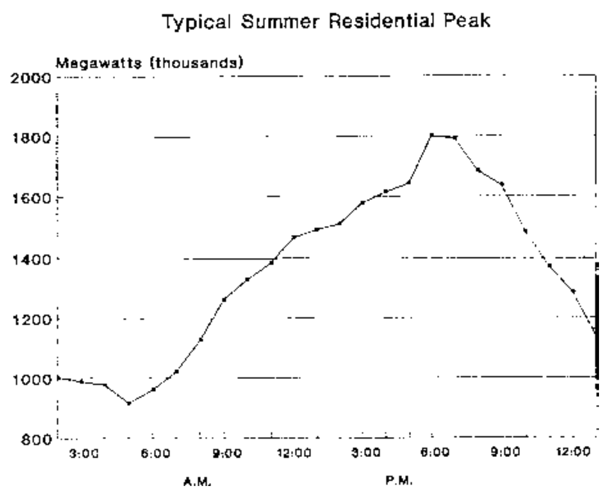


Figure 3-4 (b)

peak near 9:00 p.m. The first peak occurs when people get up in the morning and start using electricity. They all turn up their electric heat, cook breakfast, take a shower, and dry their hair at about the same time on weekday mornings. Then in the evening, they all come home from work, start cooking dinner, turn the heat back up (or use it more because nights are colder) and turn on the TV set at about the same time. Figure 3-4 (b) shows the residential summer peak demand profile for the same utility.

- **Seasonal use rate schedule.** Figure 3-5 presents a residential rate schedule where the season of use is a factor in the rate structure. This utility has chosen to attack its residential peaking problem by charging more for electricity consumed in the summer months when the highest peaks occur.

Customer charge:	\$6.50/month
Energy Charge:	On-peak season (June through October) All kWh @ 7.728¢/kWh
	Off-peak season (November through May) First 600 kWh @ 7.728¢/kWh All additional kWh @ 3.898¢/kWh
Fuel adjustment:	(Calculated by a formula provided by the utility.)

Figure 3-5. Seasonal use residential rate schedule.
(Courtesy of Oklahoma Gas and Electric Company)

During the summer peak season this utility uses a constant charge or flat rate for all energy (7.728 cents/kWh) regardless of the amount consumed. In the off-peak season, however, the utility uses a declining block approach and charges a higher rate for the first 600 kWh of energy than it does for the remaining kilowatt-hour use.

- **Time-of-day or time-of-use pricing.** To handle the daily peaking problem, some utilities charge more for energy consumed during peak times. This requires the utility to install relatively sophisticated meters. It also requires some customer habit changes. Time-of-use pricing for residential customers is not very popular today; however, most utilities are required by their state regulatory agencies to provide a time-of-use rate for customers who desire one, so most utilities have some form of time-of-use pricing.

A sample time-of-day rate for residential customers served by Florida Power Corporation is shown in Figure 3-6.

- **Peak shaving.** Some utilities offer a discount to residential customers if the utility can hook up a remote control unit to cycle large electricity using appliances in the home (usually electric heaters, air conditioners and water heaters). This utility load control program is also called *load management*. This way the utility can cycle large appliance loads on and off periodically to help reduce demand. Since the cycling is performed over short periods of time, most customers experience little to no discomfort. This approach is rapidly gaining in popularity.

A sample load management rate for residential customers served by the Clay Electric Cooperative in Keystone Heights, FL, is shown in Figure 3-7. This rate provides a rebate to customers who agree to allow the utility to turn off their electric water heaters or air conditioners for short periods of time during peak hours. Note that the Clay Electric rate also includes an inclining block feature.

3.1.5 General Service Rate Schedules

A *general service rate schedule* is used for commercial and small industrial users. This is a simple schedule usually involving only consumption (kWh) charges and customer charges. Sometimes, demand (kW) charges

Customer charge:	$16.00/month
Energy charge:	
On-peak energy	10.857¢/kWh
Off-peak energy	0.580¢/kWh
On-peak hours:	
November through March:	
Monday through Friday	6:00 a.m. to 10:00 a.m.
	6:00 p.m. to 10:00 p.m.
April through October:	
Monday through Friday	12:00 noon to 9:00 p.m.
Off-peak hours:	All other hours

Figure 3-6. Sample time-of-day electric rate.
(Courtesy Florida Power Corporation, St. Petersburg, FL)

Customer charge:	$9.00/month	
Energy charge:	First 1000 kWh @ $0.0825/kWh	
	Over 1000 kWh @ $0.0930/kWh	

Load management credit per month: Credit will be applied to the bill of all customers with load management switches who use 500 kWh or more per month as follows:

Electric water heater controlled January-December	$4.00
Electric central heating controlled October-March for 5 to 7.5 minutes of each 25-minute period	$3.00
Electric central air conditioner controlled April-September for 5 to 7.5 minutes of each 25-minute period	$3.00
Electric central heating controlled October-March for 12.5 minutes of each 25-minute period	$8.00
Electric central air conditioner controlled April-September for 5 to 7.5 minutes of each 25-minute period	$8.00

Figure 3-7. Sample load management rate for residential service.
(Courtesy of Clay Electric Cooperative, Keystone Heights, FL)

are used; this requires a demand meter. (See Section 3.1.3 for a more detailed discussion of demand charges.)

The energy charge for this customer class is often substantially higher than for residential users for various noneconomic reasons. Some of these reasons include the fact that many businesses have widely varying loads depending on the health of the economy, and many businesses close after only a few months of operation—sometimes leaving large unpaid bills. In addition, some regulatory agencies feel that residential customers should have lower rates since they cannot pass on electric costs to someone else. For example, one rate schedule charges almost 8 cents/kWh for commercial users during peak season but only a little more than 5 cents/kWh for residential users during the same season.

3.1.6 Small Industrial Rate Schedules

A *small industrial rate schedule* is usually available for small industrial users and large commercial users. The service to these customers often becomes more complex because of the nature of the equipment used in the industry, and their consumption tends to be higher. Consequently, the billing becomes more sophisticated. Usually, the same cost categories occur as in the simpler schedules, but other categories have been added. Some of these are outlined below.

3.1.6.1 Voltage level.

One degree of complexity is introduced according to what *voltage level* the customer needs. If the customer is willing to accept the electricity at transmission voltage levels (usually 50,000 volts or higher) and do the necessary transforming to usable levels on-site, then the utility saves considerable expense and can charge less. If the customer needs the service at a lower voltage, then the utility must install transformers and maintain them. In that case, the cost of service goes up and so does the bill.

The voltage level charge can be handled in the rate schedule in several ways. One is for the utility to offer a percentage discount on the electric bill if the customer owns its own primary transformer and accepts service at a higher voltage than it needs to run its equipment. Another is to increase the energy charge as the voltage level decreases. (This method is shown in the example in Figure 3-8.) Installing their own transformers is often a significant cost-cutting opportunity for industrial users and should be explored. Maintaining transformers is a relatively simple (though potentially dangerous) task, but the customer may also need to install standby transformers to avoid costly shutdowns.

3.1.6.2 Demand billing.

Understanding industrial rate structures means understanding the concept of *demand billing*. Consider Figure 3-8 where energy demands on a utility are plotted against time for two hypothetical companies. Since the instantaneous demand (kW) is plotted over time, the integration of this curve (i.e., the area under the curve) is the total energy (kWh) consumed (see shaded area). Company B and Company A have the same average demand, so the total energy consumed by B equals that of A. Company B's peak demand and its average demand are the same, but Company A has a seasonal peak that is twice as high as its average demand. Because the kWh consumed by each are equal, their bills for consumption will be equal, but this seems unfair. Company B has a very flat demand structure so the utility can gear up for that level of service with high-efficiency equipment. Company A, however, requires the utility to supply about twice the capacity that company B needs but only for one short period of time during the year. This means the utility must maintain and gear up equipment which will only be needed for a short period of time. This is quite expensive, and some mechanism must be used by the utility to recover these additional costs.

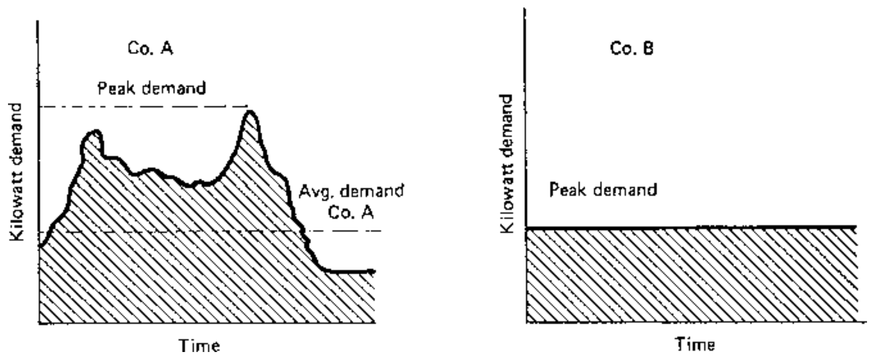


Figure 3-8 Demand profiles for two hypothetical industrial firms.

To properly charge for this disproportionate use of facilities and to encourage company A to reduce its peak demand, an electric utility will usually charge industrial users for the peak demand incurred during a billing cycle, normally a month. Often a customer can achieve substantial cost reductions simply by reducing peak demand and still consuming the same amount of electricity. A good example of this would be to move the use of an electric furnace from peaking times to nonpeaking times (maybe second or third shifts). This means the same energy could be used at less cost since the demand is reduced. A peak shaving (demand control) example will be discussed in section 3-7.

3.1.6.3 Ratchet Clause

Many utility rate structures have a ratchet clause associated with their demand rate. To understand the purpose of the ratchet clauses, one must realize that if the utility must supply power to meet a peak load in July, it must keep that equipment on hand and maintain it for the next peak load which may not occur for another year. To charge for this cost, and to encourage customers to level their demand over the remaining months, many utilities have a ratchet clause.

A ratchet clause usually says that the billed demand for any month is a percentage (usually greater than 50%) of the highest maximum demand of the previous 11 months or the actual demand, whichever is greater. The demand is normally corrected for the power factor. For a company with a large seasonal peaking nature, this can be a real problem. A peak can be set in July during a heavy air conditioning period that the company in effect pays for a full year. The impact of ratchet clauses can be significant, but often a company never realizes this has occurred.

3.1.6.4 Power factor.

Power factor is a complex subject to explain, but it can be a vitally important element in a company's electrical bill. One company the authors worked with had a power factor of 51 percent. With their billing schedule, this meant they were paying a penalty of 56.9 percent on demand billing. With the addition of power factor correction capacitors, this penalty could have been avoided or minimized.

The power factor is important because it imposes costs on a utility that are not recovered with demand and energy charges. Industrial customers are more likely to be charged for a poor power factor. They create greater power factor problems for a utility because of the equipment they use. They are also more likely to be able to correct the problem.

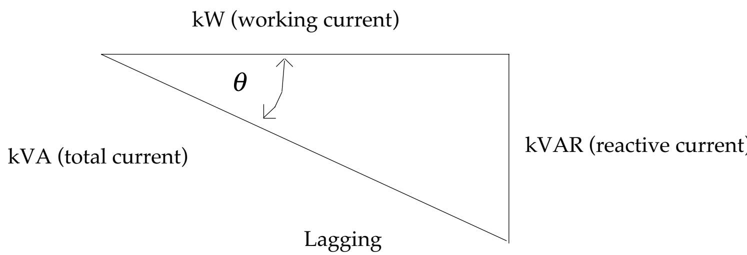
To understand the power factor, you must understand electric currents. The current required by induction motors, transformers, fluorescent lights, induction heating furnaces, resistance welders, etc., is made up of three types of current:

1. *Power-producing current* (working current or current producing real power). This is the current which is converted by the equipment into useful work, such as turning a lathe, making a weld, or pumping water. The unit of measurement of the real power produced from working current is the kilowatt (kW).

2. *Magnetizing current* (wattless or reactive current). This is the current which is required to produce the flux necessary for the operation of induction devices. Without magnetizing current, energy could not flow through the core of a transformer or across the air gap of an induction motor. The unit of measurement of the reactive power associated with magnetizing current is the kilovar (kVAR) or kilovolt-amperes reactive.

3. *Total current* (current producing apparent power or total power). This is the current that is read on an ammeter in the circuit. It is made up of the vector sum of the magnetizing current and the power-producing current. The unit of measurement of apparent power associated with this total current is the kilovoltampere (kVA). Most alternating current (ac) powered loads require both kilowatts and kilovars to perform useful work.

Power factor is the ratio of actual (real) power being used in a circuit, expressed in watts or kilowatts, to the apparent power drawn from the power line, expressed in voltamperes or kilovolt-amperes. The relationship of kW, kVAR, and kVA in an electrical system can be illustrated by scaling vectors to represent the magnitude of each quantity, with the vector for kVAR at a right angle to that for kW (Figure 3-9). When these components are added *vectorially*, the resultant is the kVA vector. The angle between the kW and kVA vectors is known as the *phase angle*. The cosine of this angle is the power factor and equals kW/kVA.



θ = phase angle = measure of net amount of inductive reactance in circuit

$\cos\theta$ = PF = ratio of *real power* to *apparent power*

$$\text{kVA} = \frac{\text{kW}}{\cos\theta} = \frac{\text{kW}}{\text{PF}} = \sqrt{(\text{kW})^2 + (\text{kVAR})^2}$$

Figure 3-9 Diagram of ac component vectors

Unless some way of billing for a low power factor is incorporated into a rate schedule, a company with a low power factor would be billed the same as a company with a high power factor. Most utilities do build in a power factor penalty for industrial users. However, the way of billing varies widely. Some of the more common ways include:

- Billing demand is measured in kVA instead of kW. A look at the triangle in Figure 3-9 shows that as the power factor is improved, kVA is reduced, providing a motivation for power factor improvement.

- Billing demand is modified by a measure of the power factor. Some utilities will increase billed demand one percent for each one percent the power factor is below a designated base. Others will modify demand as follows:

$$Billed\ Demand = Actual\ Demand \times \frac{Base\ Power\ Factor}{Actual\ Power\ Factor}$$

This way, if the actual power factor is lower than the base power factor, the billed demand is increased. If the actual power factor is higher than the base power factor, some utilities will allow the fraction to stay, thereby providing a reward instead of a penalty. Some will run the calculation only if actual power factor is below base power factor.

- The demand or consumption billing schedule is changed according to the power factor. Some utilities will change the schedule for both demand and consumption according to the power factor.

- A charge per kVAR is used. Some companies will charge for each kVAR used above a set minimum. This is direct billing for the power factor.

In addition, since a regular kW meter does not recognize the reactive power, some other measuring instrument must be used to determine the reactive power or the power factor. A kVA meter can be supplied by the utility, or the utility might decide to only periodically check the power factor at a facility. In this case a utility would send a crew to the facility to measure the power factor for a short period of time, and then remove the test meter.

3.1.6.5 The rate schedule.

The previous few sections were necessary in order to be able to present a rate schedule itself in understandable terms. All these complex terms and relationships make it difficult for many managers to understand their bills. You, however, are now ready to analyze a typical rate schedule. Consider Figure 3-10.

Effective in: All territories served

Availability: Power and light service. Alternating current. Service will be rendered at one location at one voltage. No resale, breakdown, auxiliary, or supplementary service permitted.

Rate:

A. Transmission service (service level 1):

Customer charge: $637.00/bill/month

Demand charge applicable to all kW/month of billing demand:

On-peak season: $10.59/kW
Off-peak season: $3.84/kW

Energy charge:

First two million kWh 3.257¢/kWh
All kWh over two million 2.915¢/kWh

B. Distribution service (service level 2):

Customer charge: $637.00/bill/month

Demand charge applicable to all kW/month of billing demand:

On-peak season: $11.99/kW
Off-peak season: $4.36/kW

Energy charge:

First two million kWh 3.297¢/kWh
All kWh over two million 2.951¢/kWh

C. Distribution service (service levels 3 and 4):

Customer charge: $269.00/bill/month

Demand charge applicable to all kW/month of billing demand:

On-peak season: $12.22/kW
Off-peak season: $4.45/kW

Figure 3-10. Typical small industrial rate schedule.
(Courtesy of Oklahoma Gas and Electric Company)

Energy charge:
First two million kWh 3.431¢/kWh
All kWh over two million 3.010¢/kWh

D. Secondary service (service level 5):
Customer charge: $151.00/bill/month

Demand charge applicable to all kW/month of billing demand:
On-peak season: $13.27/kW
Off-peak season: $4.82/kW

Energy charge:
First two million kWh 3.528¢/kWh
All kWh over two million 3.113¢/kWh

Definition of season:

On-peak season:	Revenue months of June-October of any year.
Off-peak season:	Revenue months of November of any year through May of the succeeding year.

Late payment charge: A late payment charge in an amount equal to one and one-half percent (1-1/2%) of the total balance for services and charges remaining unpaid on the due date stated on the bill shall be added to the amount due. The due date shall be twenty (20) days after the bill is mailed.

Minimum bill: The minimum monthly bill shall be the Customer Charge plus the applicable Capacity Charge as computed under the above schedule. The Company shall specify a larger minimum monthly bill, calculated in accordance with the Company's Allowable Expenditure Formula in its Terms and Conditions of Service on file with and approved by the Commission, when necessary to justify the investment required to provide service.

Determination of maximum demand: The consumer's Maximum Demand shall be the maximum rate at which energy is used for any period of fifteen (15) consecutive minutes of the month for which the bill is rendered as shown by the Company's demand meter. In the event a consumer taking service under this rate has a demand meter with an interval

Figure 3-10. (*Continued*)

greater than 15 minutes, the company shall have a reasonable time to change the metering device.

Determination of billing demand: The Billing Demand upon which the demand charge is based shall be the Maximum Demand as determined above corrected for the power factor, as set forth under the Power Factor Clause, provided that no billing demand shall be considered as less than 65% of the highest on-peak season maximum demand corrected for the power factor previously determined during the 12 months ending with the current month.

Power factor clause: The consumer shall at all times take and use power in such manner that the power factor shall be as nearly 100% as possible, but when the average power factor as determined by continuous measurement of lagging reactive kilovoltampere hours is less than 80%, the Billing Demand shall be determined by multiplying the Maximum Demand, shown by the demand meter for the billing period, by 80 and dividing the product thus obtained by the actual average power factor expressed in per cent. The company may, at its option, use for adjustment the power factor as determined by tests during periods of normal operation of the consumer's equipment instead of the average power factor.

Fuel cost adjustment: The rate as stated above is based on an average cost of $1.60/million Btu for the cost of fuel burned at the company's thermal generating plants. The monthly bill as calculated under the above rate shall be increased or decreased for each kWh consumed by an amount computed in accordance with the following formula:

$$F.A. = A * \frac{(B * C) \pm D}{10^6} + \frac{P}{S} + \frac{OC}{OS} \pm Y$$

where

F.A. = fuel cost adjustment factor (expressed in $/kWh) to be applied per kWh consumed

A = weighted average Btu/kWh for net generation from the company's thermal plants during the second calendar month preceding the end of the billing period for which the kWh usage is billed

Figure 3-10. (*Continued*)

B	=	amount by which the average cost of fuel per million Btu during the second calendar month preceding the end of the billing period for which the kWh usage is billed exceeds or is less than \$1.60/million Btu; any credits, refunds, or allowances on previously purchased fuel, received by the company from any source, shall be deducted from the cost of fuel before calculating B each month
C	=	ratio (expressed decimally) of the total net generation from all the company's thermal plants during the second calendar month preceding the end of the billing period for which the kWh usage is billed to the total net generation from all the company's plants including hydro generation owned by the company, or kW produced by hydro generation and purchased by the company during the same period
D	=	the amount of fuel cost per million Btu embedded in the base rate is \$2.30
P	=	the capacity and energy cost of electricity purchased by the Company, excluding any cost associated with "OC," during the second calendar month preceding the current billing month, excluding any capacity purchased in said month and recovered pursuant to Standard Rate Schedule PCR-1.
S	=	total kWh generated by the company plus total kWh purchased by the company which are associated with the cost included in "P" during the second calendar month preceding the end of the billing period for which kWh use is billed
OC	=	the difference between the cost of cogenerated power and company-generated power (Note that this factor has been simplified for purposes of this book.)
OS	=	the company's appropriate Oklahoma retail kWh sales during the twelfth billing month preceding the current billing month
Y	=	a factor (expressed in \$/kWh) to reflect 90% of the margin (profits) from the non-firm off-system sales of electricity to other utilities during the 2nd calendar month preceding the end of the billing period for which the kWh usage is billed.

Figure 3-10. (*Continued*)

Franchise payment: Pursuant to Order Number 110730 and Rule 54(a) of Order Number 104932 of the Corporation Commission of Oklahoma, franchise taxes or payments (based on a percent of gross revenue) in excess of 2% required by a franchise or other ordinance approved by the qualified electors of a municipality, to be paid by the company to the municipality, will be added pro rata as a percentage of charges for electric service, as a separate item, to the bills of all consumers receiving service from the company within the corporate limits of the municipality exacting the said tax or payment.

Transmission, distribution, or secondary service: For purposes of this rate, the following shall apply:

Transmission service (service level 1), shall mean service at any nominal standard voltage of the company above 50 kV where service is rendered through a direct tap to a company's transmission source.

Distribution service (service levels 2,3, and 4), shall mean service at any nominal standard voltage of the company between 2,000 volts and 50 kV, both inclusive, where service is rendered through a direct tap to a company's distribution line or through a company numbered substation.

Secondary service (service level 5), shall mean service at any nominal standard voltage of the company less than 2,000 volts or at voltages from 2 to 50 kV where service is rendered through a company-owned line transformer. If the company chooses to install its metering equipment on the load side of the consumer's transformers, the kWh billed shall be increased by the amount of the transformer losses calculated as follows:

1% of the total kVA rating of the consumer's transformers * 730 hours

Term: Contracts under this schedule shall be for not less than 1 year, but longer contracts subject also to special minimum guarantees may be necessary in cases warranted by special circumstances or unusually large investments by the company. Such special minimum guarantees shall be calculated in accordance with the company's allowable expenditure formula and its terms and conditions of service on file with and approved by the commission.

Figure 3-10. (*Concluded*)

Let's examine the different components in this rate structure of Figure 3-10.

- *Voltage level*. This utility has chosen to encourage company-owned primary transformers by offering a cheaper rate for both demand and consumption if the company accepts service at a higher voltage level. To analyze what it could save from primary transformer ownership, a company only needs to calculate the dollar savings from accepting service at a higher voltage level and compare that savings to the cost of the necessary transformers and annual maintenance thereof. Transformer losses must be absorbed by the company, and the company must provide a standby transformer or make other arrangements in case of a breakdown.

- *Demand billing*. This utility has chosen to emphasize demand leveling by assessing a rather heavy charge for demand.* Furthermore, the utility has emphasized demand leveling during its summer peaking season.

- *Consumption*. This utility uses a declining block rate for very large users, but this essentially amounts to a flat charge per kilowatt-hour for most consumption levels.

- *Power factor*. The utility has chosen to charge for the power factor by modifying the demand charge. They have decided all customers should aim for a power factor of at least 80 percent and should be penalized for power factors of less than 80 percent. To do this, the peak demand is multiplied by a ratio of the base power factor (80%) to the actual power factor if the actual power factor is below 80%; there is no charge or reward if the power factor is above 80%:

$$Billed\ Demand = Actual\ Demand \times \frac{Base\ Power\ Factor}{Actual\ Power\ Factor}$$

  where the base power factor =.80.

- *Ratchet clause*. The utility has a ratchet clause which says that the billed demand for any month is "65% of the highest on-peak season maximum demand corrected for the power factor" of the previous 12 months or the actual demand corrected for power factor whichever is greater.

*Actually, charges are regional. For the Southwest, this is a rather large demand charge. For the Northwest, it would be cheap.

- *Miscellaneous*. Other items appearing in the rate schedule include fuel cost adjustment, late payment charge, and minimum bill. The fuel cost adjustment is based on a formula and can be quite significant. Anytime the cost of energy is calculated, the fuel cost adjustment should be included.

- *Sales tax*. One item not mentioned in the sample schedule is sales tax. Many localities have sales taxes of 6-8% or more, so this can be a significant cost factor. The cost of electrical service should include this charge. One item of interest: Some states have laws stating that *energy used directly in production should not have sales tax charged to it*. This is important to any industry in such a state with energy going to production. Some submetering may be necessary, but the cost savings often justifies this. For example, electricity used in a process furnace should not be taxed, but electricity running the air conditioners would be taxed.

Example 3-1. As an example of rate schedule calculations, let's use the schedule in Figure 3-10 to calculate the September bill for the company whose electric use is shown below:

Month: September 1996
Actual demand: 250 kW
Consumption: 54,000 kWh
Previous high billed demand: 500 kW (July 1996)

Power factor: 75%
Service level: Secondary (PLS, service level 5)
Sales tax: 6%
Fuel adjustment: 1.15¢/kWh (This value is calculated by the utility company according to the formula given in the rate schedule.)

As a first step, the demand should be calculated:

Power factor correction:

billed demand = (actual demand) * (.80/PF)
= 250 kW * (.80/.75)
= 266.7 kW

minimum billed demand (ratchet clause)
$= (500\ \text{kW}) * (.65)$
$= 325\ \text{kW}$

billed demand $= \max.\ (266.7\ \text{kW}, 325\ \text{kW})$

billed demand $= 325\ \text{kW}$

demand charge (on-peak season)
$= (325\ \text{kW})\ (\$13.27/\text{kW})$
$= \underline{\$4312.75}$

Consumption charge:

(54,000 kWh)($.03528/kWh)	= $1905.12
(54,000 kWh)($.0115/kWh)(fuel adjustment)	= $ 621.00
total consumption charge	= $2526.12

Customer charge:

$151.00

Total charge before sales tax:

$\$4312.75 + \$2526.12 + \$151.00 = \underline{\$6989.87}$

Sales tax:

$\$6989.87 \times (.06) = \underline{\$\ 419.39}$

Total*:

$\$6989.87 + \$\ 419.39 = \underline{\$7409.26}$

3.1.7 Large Industrial Rate Schedules

Most utilities have very few customers that would qualify for or desire to be on a large industrial rate schedule. Sometimes, however, one or two large industries will utilize a significant portion of a utility's total generating capacity. Their size makes the billing more complex; therefore,

*Ignoring franchise payment and late charges.

a well-conceived and well-designed rate schedule is necessary.

Typically a large industrial schedule will include the same components as a small industrial schedule. The difference occurs in the amount charged for each category. The customer charge, if there is one, tends to be higher. The minimum kW of demand tends to be much higher in cost/kW, but all additional kW may be somewhat lower (per kW) than on small industrial schedules. Similarly, the charge per kWh for consumption can be somewhat less. The reason for this is economy of scale; it is cheaper for a utility to deliver a given amount of electrical energy to one large customer than the same amount of energy to many smaller customers.

Figure 3-11 is an example of a large industrial schedule.

STANDARD RATE SCHEDULE Rate Code No. 530

Large Power and Light (LPL)
(TITLE AND/OR NUMBER)

Availability: Available on an annual basis by written contract to any retail customer. This schedule is not available for resale, standby, breakdown, auxiliary, or supplemental service. It is optional with the customer whether service will be supplied under this rate or any other rate for which he is eligible. Once a rate is selected, however, service will continue to be supplied under that rate for a period of 12 months unless a material and permanent change in the customer's load occurs.

Service will be supplied from an existing transmission facility operating at a standard transmission voltage of 69 kV or higher by means of not more than one transformation to a standard distribution voltage of not less than 2.4 kV. Such transformation may be owned by the company or customer. Service may be supplied by means of an existing primary distribution facility of at least 24 kV when such facilities have sufficient capacity.

Service will be furnished in accordance with the company's rules, regulations, and conditions of service and the rules and regulations of the Oklahoma Corporation Commission.

Net rate: Capacity charge:

$13,750.00: net per month for the first 2500 kilowatts (kW) or less of billing demand

Figure 3-11. Large industrial rate schedule.
(Courtesy of Oklahoma Gas and Electric Co.)

$4.20: net per month per kilowatt (kW) required in excess of 2500 kW of billing demand

$.50: net per month for each reactive kilovoltampere (kVAR) required above 60% of the billing demand

Plus an energy charge:

2.700¢: net per kilowatt-hour (kWh) for the first 1 million kWh used per month

2.570¢: net per kilowatt-hour (kWh) for all additional use per month

Determination of monthly billing demand: The monthly billing demand shall be the greater of (a) 2500 kW, (b) the monthly maximum kilowatt (kW) requirement, or (c) eighty percent (80%) of the highest monthly maximum kilowatt (kW) requirement established during the previous 11 billing months. The monthly maximum reactive kilovoltampere (kVAR) required are based on 30-min integration periods as measured by appropriate demand indicating or recording meters.

Determination of minimum monthly bill: The minimum monthly bill shall consist of the capacity charge. The monthly minimum bill shall be adjusted according to adjustments to billing and kVAR charges. If the customer's load is highly fluctuating to the extent that it causes interference with standard quality service to other loads, the minimum monthly bill will be increased $.50/kVA of transformer capacity necessary to correct such interference.

Terms of payment: Payment is due within 10 days of the date of mailing the bill. The due date will be shown on all bills. A late payment charge will be assessed for bills not paid by the due date. The late payment charge shall be computed at 1-1/2 % on the amount past due per billing period.

Adjustments to billing:

1. Fuel cost adjustment: The rate as stated above is based on an average cost of $2.00/million Btu for the cost of fuel burned at the company's thermal generating plants. The monthly bill as calculated under the above rate shall be increased or decreased for each kWh consumed by an amount computed in accordance with the following formula:

Figure 3-11. (*Continued*)

$$FA = A \times \frac{B}{10^6} \times C$$

where FA= fuel cost adjustment factor (expressed in dollars per kWh) to be applied per kWh consumed

A= weighted average Btu/kWh for net generation from the company's thermal plants during the second calendar month preceding the end of the billing period for which the kWh usage is billed

B= amount by which the average cost of fuel per million Btu during the second calendar month preceding the end of the billing period for which the kWh usage is billed exceeds or is less than $2.00/million Btu; any credits, refunds, or allowances on previously purchased fuel received by the company from any source shall be deducted from the cost of fuel before calculating B each month

C= ratio (expressed decimally) of the total net generation from all the company's thermal plants during the second calendar month preceding the end of the billing period for which the kWh usage is billed to the total net generation from all the company's plants including hydrogeneration owned by the company, or kWh produced by hydrogeneration and purchased by the company, during the same period

2. Tax adjustment: If there shall be imposed after the effective date of this rate schedule, by federal, state, or other governmental authority, any tax, other than income tax, payable by the company upon gross revenue, or upon the production, transmission, or sale of electric energy, a proportionate share of such additional tax or taxes shall be added to the monthly bills payable by the customer to reimburse the company for furnishing electric energy to the customer under this rate schedule. Reduction likewise shall be made in bills payable by the customer for any decrease in any such taxes.

   Additionally, any occupation taxes, license taxes, franchise taxes,

Figure 3-11. (*Continued*)

and operating permit fees required for engaging in business with any municipality, or for use of its streets and ways, in excess of two percent (2%) of gross revenues from utility business done within such municipality, shall be added to the billing of customers residing within such municipality when voted by the people at a regularly called franchise election. Such adjustment to billing shall be stated as a separate item on the customer's bill.

Figure 3-11. (*Concluded*)

3.1.8 Cogeneration and Buy-Back Rates

Since enactment of the Public Utility Regulatory Policy Act of 1978 (PURPA), there has been significant renewed interest in on-site-generated power. This can be from cogeneration (on-site generation of thermal heat with concurrent, sequential generation of electricity), windmills, solar thermal, solar photovoltaics, or other sources. Generation of this energy for use only on site is often not cost effective due to variability of loads. Resale of excess electricity (when it is available) to the local utility, however, often makes a non-utility electric generation project economically feasible.

PURPA specified that cogenerators that met certain minimum conditions would be designated as Qualifying Facilities (QFs) and would be paid Avoided Costs by the purchasing utilities. To comply with these requirements of PURPA, utilities have developed buy-back rates for this excess electricity. Since the value of this energy may be either less than or greater than the cost to the utility of generating it, buy-back usually requires a separate meter and a separate rate schedule.*

Cogeneration can be an attractive energy cost-saving alternative for facilities that need both electric power and large amounts of steam or hot water. The combined production of electricity and thermal energy can result in fuel savings of 10-30 percent over the separate generation costs. Cogeneration will be discussed again in a later chapter.

3.1.9 Others

Many other rate schedules are being developed as the needs dictate. For example, some utilities have a rate schedule involving interruptible and curtailable loads. An interruptible load is one that can be turned off at

*Remember, the time when the industry generates an excess of electricity is probably not a peak time, so the utility really does not need the power as badly.

certain times of the day or year. A utility offers a lower rate as an incentive to companies willing to help decrease the system demand during peaking times of the day or year.

A *curtailable* load is one that the company may be willing to turn off if given sufficient notice. For example, the utility may hear of a weather forecast for extreme heat or extreme cold which would result in a severe peaking condition. It may then call its curtailable customers and ask that all the curtailable loads be turned off. Of course, the utility is willing to compensate the customers for this privilege too.

In both cases, the utility compensates its customers for these loads by offering a reduction in the bill. In the case of curtailable loads, the rate reduction occurs every month during the peaking season whether or not the utility actually calls for the turnoff. In the case of interruptible loads, the basic rate is much lower to start with.

3.2 NATURAL GAS

Natural gas rate schedules are similar in structure to electric rate schedules, but they are often much simpler. Natural gas companies also experience a peaking problem. Theirs is likely to occur on very cold winter days and/or when supply disruptions exist. Due to the unpredictable nature of these peak problems, gas utilities normally do not charge for peak demand. Instead, customers are placed into *interruptible priority classes*.

A customer with a high priority will not be curtailed or interrupted unless absolutely necessary. A customer with the lowest priority, however, will be curtailed or interrupted whenever a shortage exists. Normally some gas is supplied to keep customer's pipes from freezing and pilot lights burning. To encourage use of the low-priority schedules, utilities charge significantly less for this gas rate. Most gas utilities have three or four priority levels. Some utilities allow customers to choose their own rate schedule, while others strictly limit the choice.

Figure 3-12 presents a sample rate schedule for four priority levels. Here the industrial customer is limited in choice to priorities 3 and 4.

Some points are demonstrated in this collection of schedules. First, the energy costs decrease as the priority goes down, but the probability of a curtailment or interruption dramatically increases. Second, the winter residential rate has an increasing block component on the block of gas use over 10 Mcf/month. Only very large residential consumers would approach this block, so its intent is to discourage wanton utilization. Like

Residential Priority 1	
Winter	
First 1 ccf/mo	$5.12
Next 2.9 Mcf/mo	$5.347/Mcf
Next 7 Mcf/mo	$3.530/Mcf
Over 10 Mcf/mo	$3.725/Mcf
Summer	
First 1 ccf	$5.12/Mcf
Next 2.9 Mcf/mo	$5.347/Mcf
Over 3 Mcf/mo	$3.633/Mcf

Commercial Priority 2	
Winter	
First 1 ccf/mo	$6.79
Next 2.9 Mcf/mo	$5.734/Mcf
Next 7 Mcf/mo	$5.386/Mcf
Next 90 Mcf/mo	$4.372/Mcf
Next 1900 Mcf/mo	$4.127/Mcf
Next 6000 Mcf/mo	$3.808/Mcf
Over 8000 Mcf/mo	$3.762/Mcf
Summer	
First 1 ccf	$6.79
Next 2.9 Mcf/mo	$5.734/Mcf
Next 7 Mcf/mo	$5.386/Mcf
Next 90 Mcf/mo	$4.372/Mcf
Next 100 Mcf/mo	$4.127/Mcf
Next 7800 Mcf/mo	$3.445/Mcf
Over 8000 Mcf/mo	$3.399/Mcf

Industrial Priority 3 (Second Interruptible)	
First 1 ccf	$19.04
Next 2.9 Mcf/mo	$5.490/Mcf
Next 7 Mcf/mo	$5.386/Mcf
Next 90 Mcf/mo	$4.372/Mcf
Next 100 Mcf/mo	$4.127/Mcf
Next 7800 Mcf/mo	$3.445/Mcf
Over 8000 Mcf/mo	$3.399/Mcf

Industrial Priority 4 (First Interruptible)	
First 4000 Mcf/mo or fraction thereof	$12,814.00
Next 4000 Mcf/mo	$3.168/Mcf
Over 8000 Mcf/mo	$3.122/Mcf

Summer periods include the months from May through October.
Winter periods include the months from November through April.

Figure 3-12. Gas schedules for one utility.
(Courtesy Oklahoma Natural Gas Company)

electric rates, fuel cost adjustments do exist in gas rates. Sales taxes also apply to natural gas bills. Again, some states do not charge sales tax on gas used directly in production.

Natural gas rates differ significantly in different parts of the country. Gas is relatively cheap in the producing areas of Oklahoma, Texas and Louisiana. It is much more expensive in other areas where it must be transported over long distances through transmission pipes. For example, in Florida, gas is almost twice as expensive as shown in the rate structure of Figure 3-12. Gas supplied by Gainesville Regional Utilities (Gainesville, FL) is priced under a flat rate structure (i.e. it does not drop in price with increased use). It costs around $6.00/Mcf for residential use, and almost $5.00/Mcf for commercial use. Interruptible gas service for larger users costs about $4.00/Mcf.

3.3 FUEL OIL AND COAL

Fuel oils are a very popular fuel source in some parts of the country, but they are rarely used in others. Natural gas and fuel oil can generally be used for the same purpose so the availability and price of each generally determines which is used.

Fuel oils are classified as *distillates* or *residuals*. This classification refers to the refining or distillation process. Fuel oils Number 1 and 2 are distillates. No. 1 oil can be used as a domestic heating oil and diesel fuel. No. 2 oil is used by industry and in the home. The distillates are easier to handle and require no heat to maintain a low viscosity; therefore, they can be pumped or poured with ease.

Residual fuel oils include Nos. 4, 5 and 6. Optimum combustion is more difficult to maintain with these oils due to variations in their characteristics that result from different crude oil origins and refining processes. No. 6 or residual bunker C is a very heavy residue left after the other oils have been refined. It has a very high viscosity and must be heated in cold environments to maintain a *pour point* (usually somewhere around 55°F).

The sulfur content of fuel oil normally ranges from .3 to 3.0 percent. Distillates have lower percentages than residuals unless the crude oil has a very high sulfur level. Sulfur content can be very important in meeting environmental standards and thus should be watched carefully.

Billing schedules for fuel oils vary widely among geographical areas of the country. The prices are set by market conditions (supply vs. demand), but within any geographical area they are fairly consistent. Within each fuel oil grade, there is a large number of sulfur grades, so shopping around can sometimes pay off. Basically, the price is simply a flat charge per gallon, so the total cost is the number of gallons used times the price per gallon.

Like fuel oil, coal comes in varying grades and varying sulfur content. It is, in general, less expensive than fuel oil per Btu, but it does require higher capital investments for pollution control, coal receiving and handling equipment, storage, and preparation. Coal is priced on a per ton basis with provisions for or consideration of sulfur content and percent moisture.

Finally, coal does not burn as completely as other fuels. If combustion air is properly controlled, natural gas has almost no unburned combustibles, while fuel oil has only a small amount. Coal, however, is much more difficult to fully combust.

3.4 STEAM AND CHILLED WATER

In some areas of the country, customers can purchase steam and chilled water directly instead of buying the fuel and generating their own. This can occur where there are large-scale cogeneration plants (steam), refuse-fueled plants (steam), or simple economics of scale (steam and/or chilled water). In the case of both steam and chilled water, it is normal to charge for the energy itself (pounds of steam or ton-hours of chilled water) and the demand (pounds of steam per hour or tons of chilled water). A sample hypothetical rate schedule is shown in Figure 3-13.

These rates are often competitive with costs of self-generated steam and chilled water. Purchasing steam and chilled water conserves considerable amounts of capital and maintenance monies. In general, when steam or chilled water is already available, it is worthy of consideration. The primary disadvantage is that the user does not have control of the generating unit. However, that same disadvantage is also true of electricity for most facilities.

3.5 WATER AND WASTEWATER

The energy analyst also frequently looks at water and wastewater use and costs as part of the overall energy management task. These costs are often related to the energy costs at a facility, and are also amenable to cost control. Water use should be examined, and monthly bills should be analyzed similarly to energy bills to see if unusual patterns of consumption are occurring. Water treatment and re-use may be cost effective in areas where water costs are high.

Wastewater charges are usually based on some proportion of the metered water use since the wastewater solids are difficult to meter. This can needlessly result in substantial increases in the utility bill for processes which do not contribute to the wastewater stream (e.g., makeup water for cooling towers and other evaporative devices, irrigation, etc.). A water meter can be installed at the service main to measure the loads not

Steam

Steam demand charge:

$1500.00/month for the first 2000 lb/h of demand or any portion thereof

$550.00/month/1000 lb/h for the next 8000 lb/h of demand

$475.00/month/1000 lb/h for all over 10,000 lb/h of demand

Steam consumption charge:

$3.50/1000 lb for the first 100,000 lb of steam per month

$3.00/1000 lb for the next 400,000 lb of steam per month

$2.75/1000 lb for the next 500,000 lb of steam per month

$2.00/1000 lb for the next 1 million lb of steam per month

Negotiable for all over 2 million lb of steam per month

Chilled water

Chilled water demand charge:

$2500.00/month for the first 100 tons of demand or any portion thereof

$15.00/month/ton for the next 400 tons of demand

$12.00/month/ton for the next 500 tons of demand

$10.00/month/ton for the next 500 tons of demand

$9.00/month/ton for all over 1500 tons of demand

(One ton is defined as 12,000 Btu/h, and an hour is defined as any 60 consecutive min.)

Chilled water consumption charge:

$.069/ton • h for the first 10,000 ton • h/month

$.06/ton • h for the next 40,000 ton • h/month

$.055/ton • h for the next 50,000 ton • h/month

$.053/ton • h for the next 100,000 ton • h/month

$.051/ton • h for the next 100,000 ton • h/month

$.049/ton • h for the next 200,000 ton • h/month

$.046/ton • h for the next 500,000 ton • h/month

Base rates: Consumption rates subject only to escalation of charges listed in conditions of service and customer instructions

Figure 3-13. Hypothetical steam and chilled water rate schedule.

returning water to the sewer system. This can reduce the wastewater charges by up to two-thirds.

3.6 MONTHLY ENERGY BILL ANALYSIS

Once the energy rate structures have been examined, management should now understand how the company is being charged for the energy it uses each month. This is an important piece of the overall process of energy management at a facility. The next step in the examination of energy costs should be to review the bills and determine the average, peak and off-peak costs of energy used during at least the past twelve months.

Energy bills should be broken down into components that can be controlled by the facility. These cost components can be listed individually in tables and then plotted. For example, electricity bills should be categorized by demand costs per kW per month, and energy costs per kWh. The following example illustrates this analysis for an industry in Florida.

Example 3-2. A company in central Florida that fabricates metal products receives electricity from its electric utility at the following general service demand rate structure.

Rate structure:
(Minimum demand of 20 kW/month to qualify for rate)

Customer cost	= $21.00 per month
Energy cost	= $0.04 per kWh
Demand cost	= $6.50 per kW per month
Taxes	= Total of 8%
Fuel adjustment	= A variable amount per kWh each month (which may be a cost or a credit depending on actual fuel costs to the utility).

The electric energy use and costs for that company for a year are summarized below.

The energy analyst must be sure to account for all the taxes, the fuel adjustment costs, the fixed charges, and any other costs so that the true cost of the controllable energy cost components can be determined. In the electric rate structure described above, the quoted costs for a kW of demand and a kWh of energy are not complete until all these additional costs are added. Although the rate structure says that there is a basic charge of \$6.50 per kW per month, the actual cost including all taxes is \$7.02 per kW per month. The average cost per kWh is most easily obtained by taking the data for the 12-month period and calculating the cost over that period of time. Using the numbers from the table, one can see that this company has an average energy cost of (\$42,628.51)/(569,360 kWh) = \$0.075 per kWh.

Summary of Energy Usage and Costs

Month	kWh Used (kWh)	kWh Cost (\$)	Demand (kW)	Demand Cost (\$)	Total Cost (\$)
Mar	44960	1581.35	213	1495.26	3076.61
Apr	47920	1859.68	213	1495.26	3354.94
May	56000	2318.11	231	1621.62	3939.73
Jun	56320	2423.28	222	1558.44	3981.72
Jul	45120	1908.16	222	1558.44	3466.60
Aug	54240	2410.49	231	1621.62	4032.11
Sept	50720	2260.88	222	1558.44	3819.32
Oct	52080	2312.19	231	1621.62	3933.81
Nov	44480	1954.01	213	1495.26	3449.27
Dec	38640	1715.60	213	1495.26	3210.86
Jan	36000	1591.01	204	1432.08	3023.09
Feb	42880	1908.37	204	1432.08	3340.45
Totals	569,360	\$24,243.13	2,619	\$18,385.38	\$42,628.51
Monthly Averages	47,447	\$2,020.26	218	\$1,532.12	\$3,552.38

The utility cost data are used initially to analyze potential Energy Management Opportunities (EMOs) and will ultimately influence which EMOs are recommended. For the example above, an EMO that reduces peak demand would save the company \$7.02 per kW per month. Therefore, the energy analyst should consider EMOs that would involve using certain equipment during the night shift when the peak load is significantly lower than the first shift peak load. EMOs that save both energy and demand on the first shift would save costs at a rate of \$0.075 per kWh. Finally, EMOs that save electrical energy during the off-peak shift should be examined too, but they may not be as advantageous; they would only save at the rate of $0.043 per kWh because they are already using off-peak energy and there would not be any additional demand cost savings.

The energy consumption should be plotted as well as tabulated to show the patterns of consumption pictorially. The graphs often display some unusual feature of energy use, and may thus help highlight periods of very high use. These high-use periods can be further examined to determine whether some piece of equipment or some process was being used much more than normal. The energy auditor should make sure that any discrepancies in energy use are accounted for. Billing errors can also show up on these plots, although such errors are rare in the authors' experience.

Figures 3-14 and 3-15 show graphs of the annual kilowatt-hour and kilowatt billing for the data from the preceding example. An energy auditor examining these graphs should ask a number of questions. Because the months of May through October are warm months in Florida, the kilowatt-hour use during these months would be expected to be higher than during the winter months. However, July shows unexpectedly low usage. In this case the company took a one-week vacation during July, and the plant energy consumption dropped accordingly. In other cases, this kind of discrepancy should be investigated, and the cause determined. The variations between December, January and February again bear some checking. In this example, the plant also experienced shutdowns in December and January. Otherwise, the facility's kilowatt-hour use seems to have a fairly consistent pattern over the twelve-month period.

Kilowatt use also needs some examination. The 18 kW jump from April to May is probably the result of increased air-conditioning use. However, the 9 kW drop from May to June seems odd especially since kilowatt-hour use actually increased over that period. One might expect demand to drop in July commensurate with the drop in energy use, but as long as the plant operated at normal capacity on any day during the month of July, it would be likely to establish about the same peak demand as it did in June. Other causes of large variations for some facilities can be related to meter reading errors, equipment and control system malfunctions, and operational problems.

3.7 ACTIONS TO REDUCE ELECTRIC UTILITY COSTS

Typical actions to reduce kWh consumption involve replacing existing lights with more efficient types; replacing electric heating and cooling

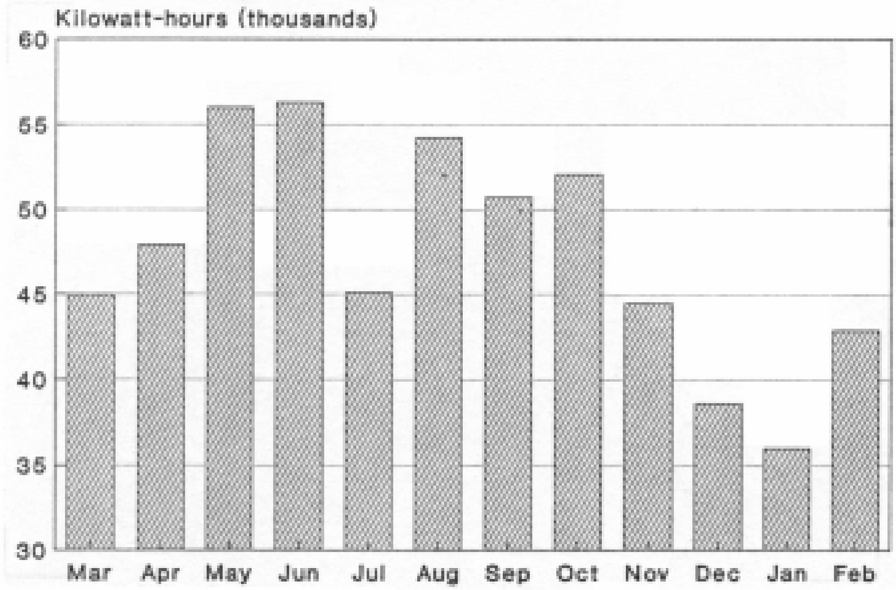


Figure 3-14

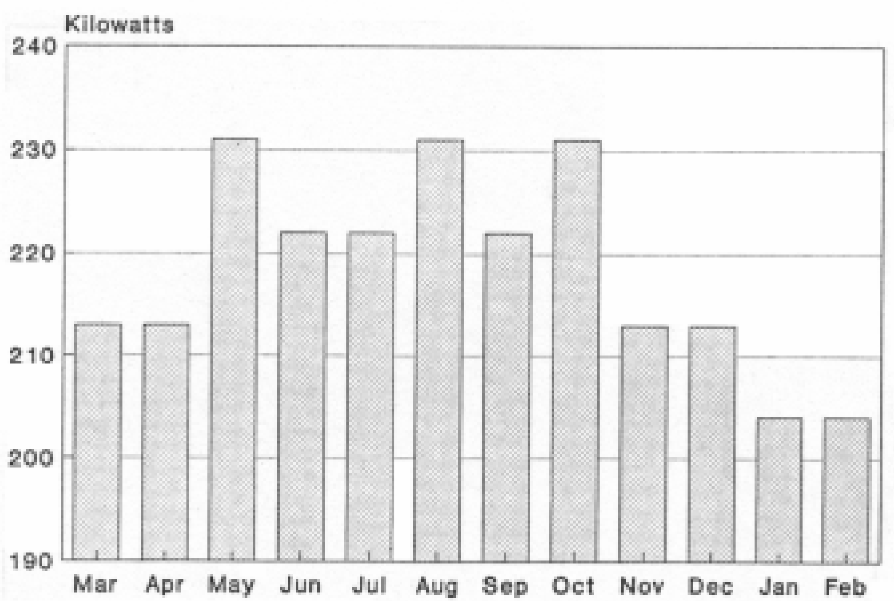


Figure 3-15

equipment with more efficient models; adding insulation to walls and ceilings; replacing motors with high efficiency models and using variable speed drives; recovering heat from air compressors, refrigeration units, or production processes to heat water for direct use or to pre-heat water for steam production; and replacing manufacturing or process equipment by more energy efficient models or processes.

Most of these actions will also result in demand reductions and produce savings through lower kW charges. Other actions that specifically reduce demand involve controlling and scheduling existing loads to reduce the peak kW value recorded on the demand meter. An energy management computer that controls demand is usually better than manual control or time-clock control. If several large motors, chillers, pumps, fans, furnaces or other high kW loads are in use at a facility, then electric costs can almost always be saved through demand limiting or control. All of these areas for savings will be examined in detail in the subsequent chapters.

Example 3-3. As an example of the savings that can be obtained by demand control, consider the use of four large machines at a production facility where each machine has a demand of 200 kW. The machines could be controlled by a computer which would limit the total demand to 400 kW at any one time. This company has chosen to limit the use of the machines by operational policy which states that no more than two machines should be turned on at any given time.

One morning at 8:00 am a new employee came in and turned on the two idle machines. At 8:30 am the plant foreman noticed that too many machines were running and quickly shut down the extra two machines. What did this employee's mistake cost the facility?

The immediate cost on the month's electric bill has two components. Using the demand rate from Example 3.2, the immediate cost is calculated as:

Demand cost increase = 400 kW * $7.02/kW
= $2808

Energy cost increase = 400 kW * 0.5 hr * $.043/kWh
= $8.60 for the energy.

If the utility rate structure includes a 70% demand ratchet, there would be an additional demand for the next 11 months of (.70 * 800 kW) – 400 kW = 160 kW. This would further increase the cost of the mistake as follows:

Ratchet cost increase	= 11 mo * $7.02/kW mo * 160 kW
	= $12,355.20.
Total cost of mistake	= $2808 + $8.60 + $12,355.20
	= $15,171.80

Under certain conditions a customer may be able to save money by shifting to another rate category [2]. Consider the example of a manufacturing facility which has a meter for the plant area and a separate meter for the office area. The plant is on a demand rate, but the office area is on a non-demand rate since it has a typical demand of around 19 kW for any month. Under the demand rate structure in section 3.6 customers are billed on the demand rate for one full year starting from any month in which their demand exceeds 20 kW for any 30 minute time window. If the office area could establish a very short peak demand of 20 kW or greater for one month it would automatically be shifted to the demand rate, and could likely benefit from the lower cost per kWh on that rate.

3.8 UTILITY INCENTIVES AND REBATES

Many utility rate structures include *incentives* and *rebates* for customers to replace old, energy inefficient equipment with newer, more energy efficient models. Utilities offer such incentives and rebates because it is cheaper for them to save the energy and capacity for new customers than it is to build new power plants or new gas pipelines to supply that additional load. In addition, stringent environmental standards in some areas makes it almost impossible for electric utilities to build and operate new facilities—particularly those burning coal. Helping customers install more energy efficient electrical and gas equipment allows utilities to delay the need for new facilities, and to reduce the emissions and fuel purchases for the units they do operate.

Direct incentives may be in the form of low interest loans that can be paid back monthly with energy savings resulting from the more efficient equipment. Incentives may also be in the form of lower rates for the electricity used to run higher efficiency lights and appliances, and more efficient process equipment. Other incentives include free audits from the utilities and free technical assistance in identifying and installing these energy efficiency improvements.

Indirect incentives also exist, and are often in the form of a special rate for service at a time when the utility is short of capacity, such as a time of day rate or an interruptible rate. The time of day rate offers a lower cost of electricity during the off-peak times, and often also during the off-season times. Interruptible rates allow large use customers to purchase electricity at very low rates with the restriction that their service can be interrupted on short notice. (See Section 3.1.9 for a discussion of interruptible and curtailable loads.)

Rebates are probably the most common method that utilities use to encourage customers to install high efficiency appliances and process equipment. Utilities sometimes offer a rebate tied to the physical device—such as \$1.00 for each low-wattage fluorescent lamp used or \$10.00 per horsepower for an efficient electric motor. Other rebates are offered for reductions in demand—such as \$250 for each kW of demand that is eliminated. Metering or other verification techniques may be needed to insure that the proper kW reduction credit is given to the customer. The load management rate structure shown in Figure 3-7 is a form of rebate for residential customers.

Incentives or rebates can substantially improve the cost effectiveness of customer projects to replace old devices with new, high efficiency equipment. In some cases, the incentives or rebates may be great enough to completely pay for the difference in cost in putting in a high efficiency piece of equipment instead of the standard efficiency model. Additional discussion and examples of utility incentives and rebates, and how they affect equipment replacement decisions is provided in subsequent chapters.

3.9 ELECTRIC UTILITY COMPETITION AND DEREGULATION

Within a short time of the passage of the national Energy Policy Act of 1992 (EPACT), electric utility interest in DSM programs and levels of rebates and incentives began to decline. EPACT contained a provision that mandated open transmission access—that is, requiring competing utilities to open up their transmission systems to wholesale transactions and wholesale wheeling of power between utilities. EPACT left the issue of retail access—or retail wheeling—in the hands of individual state regulatory agencies. However, EPACT left no doubt that utility deregulation and competition was coming. Within two years of the passage of EPACT, a dozen or more states were actively pursuing retail wheeling experiments or retail wheeling legislation.

Utilities quickly began to restructure their businesses, and began massive cost reductions. The utilities were preparing for becoming the "lowest cost supplier" to their customers, and they feared that some other utility might have lower costs and could eventually capture many of their largest and most lucrative customers. DSM programs were scaled back by most utilities, and were eliminated by others. Rebates and incentives were reduced or eliminated by many utilities, as these were perceived as unnecessary costs and activities in the face of the coming deregulation and retail wheeling. A number of utilities have kept their rebates or incentives, so some of these are still available.

Utility restructuring is proceeding at a fast pace in those states with high electricity prices, and at a much slower pace in states with low prices. California, New York and Massachusetts have some of the most advanced restructuring plans as of early 1997. California will have a restructured competitive market by January 1, 1998. New York will have wholesale competition in early 1997 and retail access in early 1998. Massachusetts will have retail choice in January 1998. Vermont is not quite as far along, but will have a date for retail access in the near future.

In the meantime, many states have experimental programs underway for retail wheeling. Retail access pilot programs are underway in Illinois, Massachusetts, Michigan, New Hampshire, New York, and Wisconsin. Rhode Island's program will begin July 1, 1997; and Pennsylvania will open one-third of that state's market to competition on January 1, 1999. Other states which are considering retail access at this time (early 1997) include Iowa, Maine, Minnesota, and Texas. Other states are not as far along in the restructuring process at this time.

Many of the same marketing features available for years in deregulated natural gas purchasing will become available for purchasers of electric power. These include the use of brokers, power marketers and risk managers. The brokers will arrange for the purchase of power for customers and the purchase and sale of power for customers who are self-generators. Power marketers will purchase the rights to certain amounts of electric power and will then re-sell it to other purchasers. Risk managers will basically sell futures contracts to help purchasers achieve stable longer-term prices.

The move to deregulation and retail wheeling will have a dramatic effect on future electricity prices for all large customers. Prices will decline for all large customers, and will decline significantly for many larger facilities. Instead of projecting higher electric costs in the future, these customers should be projecting lower costs. Medium-sized customers should also see cost reductions. The impact on small customers—particularly residential customers—is still unknown in most cases. Some will also see lower prices, but some are likely to actually experience price increases.

In the near term, some energy managers for larger and medium-sized organizations may find themselves more involved with utility programs to provide lower cost electricity than with programs to save energy and demand. Some energy efficiency projects may even have to wait for approval until the final economic analysis can be calculated with the new cost of electricity. However, when the pricing of electricity settles down to its final range in the near future, energy managers will find themselves back in the previous business of finding ways to implement new equipment and processes to save energy and demand.

3.10 SUMMARY

In this chapter we analyzed rate schedules and costs for electricity in detail. We also examined rates and costs for natural gas, coal, fuel oil, steam, and chilled water. A complete understanding of all the rate schedules is vital for an active and successful energy management program.

In the past, few managers have understood all of the components of these rate schedules, and very few have even seen their own rate schedules. The future successful manager will not only be familiar with the terms and the schedules themselves, but he or she will also likely work with utilities and rate commissions toward fair rate-setting policies.

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