A Peak Load Pricing Policy for North Carolina Utilities

In the early 1970's North Carolina electric utility companies planned to embark on construction projects for new plants costing billions of dollars. But, for the first time in the history of the state, power firm policies fell upon turbulent waters. Soaring electric rates had resulted in a tide of consumer outrage. Legislative efforts delayed the companies from sailing their original courses. Questions were being raised about utility pricing policies.

In 1975, the North Carolina legislature adopted a measure by Senator McNeill Smith to require the state Utilities Commission to hold public hearings on peak load pricing and the future needs for electricity in the state. After the December, 1975 hearings, the Commission ordered the utilities to submit plans to implement this form of pricing.

With peak load pricing, a consumer is charged a rate based upon the time of day he uses the electricity. This system charges a lower rate for off-peak use to encourage electricity consumption at off-peak periods. Advocates of peak load pricing, sometimes called time of day or marginal cost pricing, claim there could be an immediate reduction in average monthly bills and that construction programs for new generating capacity to meet peak demand would be delayed for a significant period in the future.

"With peak load pricing, a consumer is charged a rate based upon the time of day he uses electricity."

The present rate structure is left over from the past when average costs for generating electricity were declining. Back then, people never used to worry whether they turned off lights in empty rooms or tried to conserve electricity in other ways. Most people did not question or understand the reason for the rate structure, because as their use increased, they got a cheaper rate, something like a bulk rate. They felt it was not worth the effort to conserve energy because it did not lower their monthly bill very much.

People were behaving exactly as the economic text books predicted. The declining block rate structure lowered the unit cost as more electricity was consumed. This meant that the last unit cost less than the average price. Even though electric bills rose with increased consumption, the added cost of using one more unit was small.[1]

Why the Increase in Electrical Rates?

In 1973, the oil embargo by the Organization of Petroleum Exporting Countries (OPEC) and the ensuing "energy crisis" raised our consciousness about a phenomenon that had begun several years earlier. Energy prices were rising. In North Carolina in 1961 the average price for one kilowatt* hour of electricity was 0.0125 dollars. In 1967, that price had dropped to 0.011 dollars. But by 1975, the average price had climbed to 0.0265 dollars and is still climbing.[2] There were several reasons for this change.

In the 1950's and 1960's the electric companies took advantage of economies of scale as they built larger and larger generating plants. The price of various fuels was nearly constant and these two factors combined to cause a decreasing cost of electricity generation. The only rate cases heard by the Utilities Commission were requests by the utility companies for decreases in rates. Meanwhile, the public enjoyed a substantial increase in real income, making it that much more difficult to get excited about the technical aspects of efficiency in electricity generation.

Electric power generating plants continued to expand. But, sometime in the early 1970's the electric utilities industry ran out of economies of scale and the costs of electricity and of additional generating plants began a rapid rise. This phenomenon, coupled with the sudden increase in oil and coal prices has spurred the abrupt jump in electrical rates.

Is the Existing Rate Structure Part of the Problem?

The present rate structures were drawn up in the old days. Since large generating plants were more efficient and had smaller average costs than the small

**A kilowatt is an amount of electricity used at any moment. An electric toaster might have a demand of 1,000 watts or one kilowatt. The same toaster if operated for an hour would consume one kilowatthour (kwh) of electricity.*

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Duke Power's Belews Creek Plant

Photo courtesy Duke Power Co.

plants, it seemed clear that if people could be induced to use more electricity, more efficient plants could be built and everyone would benefit from lower average electric rates. Therefore, the declining block system became the traditional way of pricing. The power company calculated the total expected cost of producing the electricity which included a "fair" rate of return on its capital, and divided by the number of kilowatt hours it expected to generate. This way it arrived at a price per kilowatt hour. This average price was then modified to charge a higher rate for the small user and a lower rate for the large consumers. Consumers were rewarded with lower rates if they used devices that consumed large quantities of electricity, like hot water heaters and electric heating for houses.

The result today, however, is not a lower average cost for generating electricity, but a higher cost, revealing the relation between cost and output. This cost of new expensive generating capacity, encouraged under the present system, is spread to all consumers in the form of higher average electric bills. It is one source of inefficiency in electricity generation.

A second inefficiency results from having prices and costs not directly related to each other. Under existing conditions, the cost of generating electricity increases with the amount being generated, because the most efficient generating plants are brought in first. In 1974, the fuel cost alone varied from 0.00186 dollars to 0.02768 dollars per kilowatt hour in the Duke system.[3] Average costs in the system are increasing with total use. Therefore, the cost of generating electricity at periods of peak demand is greater than the cost of generating it at times of low use. But people pay the same amount regardless of when they use it. Since this rate is charged at all times, the consumer has no incentive to plan to select the time of his use. The result is a greater demand at peak times, which requires the power companies to maintain additional expensive generating plants. The consumer is caught in a precarious position within an inefficient pricing system—a pricing system that encourages greater total use and greater peak use. What are the alternatives? What would be the effects of using a different approach? A good starting place to look for these answers is to examine the way other goods are distributed and priced.

The Competitive Model

In a competitive economic system, the consumers ultimately decide how a nation will allocate its scarce and limited resources by casting dollar votes in the market place. Consumers decide, for example, if the nation is to have an abundant supply of automobiles, rather than a well developed mass transit system.*

In all cases, the individual consumer decides whether or not to buy something by comparing the expected benefit with the price. In any competitive market, the prices of manufactured commodities reflect the marginal cost of producing the commodities.

The electric utilities industry is not a part of the competitive system. In the past, the first company to supply electricity to an area became the monopoly supplier. To protect citizens from monopoly power, states established commissions to regulate these industries.

On the one hand, the commission has a chance to set electricity prices in any way it chooses. On the other hand, the commission has the very difficult task of performing the functions that occur automatically through the interaction of producers and consumers in the competitive sector. The commission faces the problem of making the interrelated decision of how much electric capacity to have, and how to set the price signals that consumers use to decide how much electricity they want and when they want it.

There is an important distinction between a competitive market and a monopoly or non-competitive

**John Kenneth Galbraith would argue that in the real world of giant monopolies, corporations are able to cajole, coerce, and deceive the consumer into buying what the corporations want to sell. Barry Commoner in the Poverty of Power argues that the demise of public transit in the U.S. was helped along by General Motors buying up municipal trolley systems and shutting them down.*

system. The price is always a signal to the consumer for deciding how much of each item to purchase in both systems, but only in a perfectly competitive system must the price represent the marginal cost to the society of producing each item.

Marginal Cost Pricing

In a competitive market a producer does not set the price. The market determines the going price and the producer decides how much of this item to produce by comparing the price with his marginal cost.

The marginal cost is the cost of producing an extra unit or the difference in his total costs now and his total costs when he produces one more unit. If the marginal cost to produce a pencil, for example, is only two cents, but the market price is three cents, the manufacturer will continue to produce pencils and expand his output. When the marginal cost to produce the pencil equals the market price of three cents he will not produce beyond this quantity because the addition to cost would be greater than the increase in revenue which is market price. He will not, for example, want to expand production to a point where the marginal cost of that pencil is three and a half cents, half a cent above the market price. In a competitive system, all production will be such that the price of each good is equal to its marginal cost.

In the above case of pencils, this is a readily applied concept. In the case of electricity production and throughout this paper, however, the large scale and expense of generating plants make it appropriate to consider Long Run Marginal Cost (LRMC). The marginal cost is always the cost of producing another unit; however, when producing another unit involves building a new multi-billion dollar plant, this new capacity cost must be considered in calculating the marginal cost at levels of output which press against capacity. Since the cost of each new plant is greater than the last one, and it does not matter why the costs are increasing (it might be due to construction or capacity or pollution controls etc.), the appropriate long run marginal cost must reflect the cost of increasing the output. This is necessary if the optimal amount of generating capacity in the system is to be determined. In the long run, the desired amount of new capacity can be determined only by seeing how much electricity people want to use at a price that includes the potential cost of new capacity.

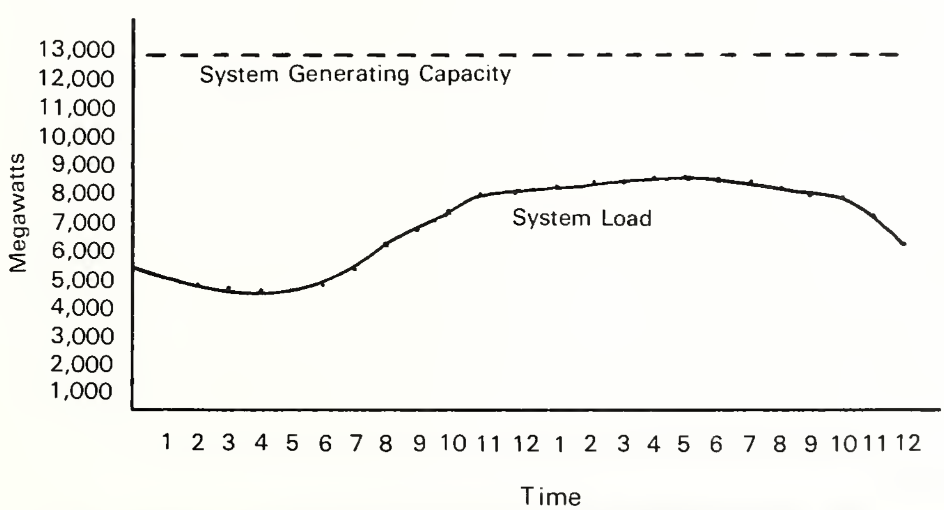
Because marginal cost pricing means setting the price equal to the cost of producing one more unit, it is irrelevant that some of the peaking electricity comes from hydro plants which have low marginal costs until they are fully used. The appropriate price is the cost of another KWH to the system. The general theory tells us that incremental capital costs should be included in the prices attached to the time period in which use presses against capacity. This is fair since it allocates the new construction costs to those who demand electricity during peak periods, and who, therefore, are making the new construction necessary.[4] On the other hand, including the cost of new construction might well decrease demand, and make construction of new generating plants unnecessary. "Both the British and the French electricity industries have reported improvements in system load factors of between 10 and 20 percent."[5] At the present time in the Duke system, which recorded 44 per cent reserves during its greatest peak, this would not have a matter of practical importance in rate setting. However, if and when the system demand does increase enough to approach capacity, then the marginal cost prices will reflect this marginal construction cost, and should result in equitable and efficient distribution of the costs.

The Present System is in Conflict with the Competitive Model

Regulatory commissions now set a price for electricity that has no relationship to the marginal cost of generating it. The price of electricity, though, still remains the signal on which the consumer bases the decision to purchase or not to purchase. But that price has no direct relationship to the cost to society of producing it. *The present pricing system leads to less*

Figure 1

Duke Power Company System Load for Day of Greatest Summer Peak, Monday, August 25, 1975



use of cheap off-peak electricity and more use of the expensive peak electricity. Therefore the average cost of all electricity generation is increased.

If the consumer were charged for the average costs of the products he used, the market place would be chaotic, like the supermarket described by Columbia University economist William Vickery, at the peak load pricing hearings before the North Carolina Utilities Commission during December, 1975.

To eliminate the bother of checkout counters, the supermarket would do away with the present marginal cost pricing system and institute an average price for all the goods based only on the weight of the purchase. For example, an economist might find the average price per pound by weighing all expected purchases at the grocery stores and dividing the entire weight into the desired revenue.

This pricing system would facilitate matters at the checkout station and probably eliminate lines. A simple scale would weigh each consumer's purchase and the bill would be based upon a fixed price per pound.

The result of this pricing scheme is predictable, said Vickery. The consumer would buy considerably more steak and less potatoes, and the supermarket would go broke. If this were a monopoly situation with no competing stores, then it could stay in business by substantially raising the average price.

Illustrative Examples

Figure 1, the August 25, 1975, daily pattern for the Duke system, illustrates the variation of demand over a 24-hour period for the day of the highest summer peak demand. The lowest demand was 4,503 megawatts at 5 a.m. The average demand for the day was 6,834 megawatts and was reached between 9 and 10 a.m. The greatest peak demand was over 8,400 megawatts and occured between 5 p.m. and 6 p.m.*

In Figure 2, MC shows the relationship between the marginal cost of generating the electricity and the amount being generated. This curve starts at a low level, corresponding to the use of the least expensive base load generating plants, then increases as the intermediate plants are brought in, and finally increases sharply as the "peaking" plants are added. As the limits of capacity are reached, this curve includes the cost of building new generating capacity to satisfy a further increase in demand and rises even more steeply. Graph (1) represents the demand shown in

**At this same time Duke Power had over 12,400 megawatts of installed generating capacity. About 40 per cent of capacity was idle at the time of greatest use. This level of reserves is more than double the amount considered desirable in the industry. In general, utilities like to have between 15 and 20 per cent reserves. This amount should be computed considering the possible purchases from neighboring systems. It should be added that the reserve is needed only as long as prices are not flexible so that there is no way to discourage use during a temporary shutdown of a plant.*

Figure 2

Different Pricing Systems and the Effects on Electricity Use

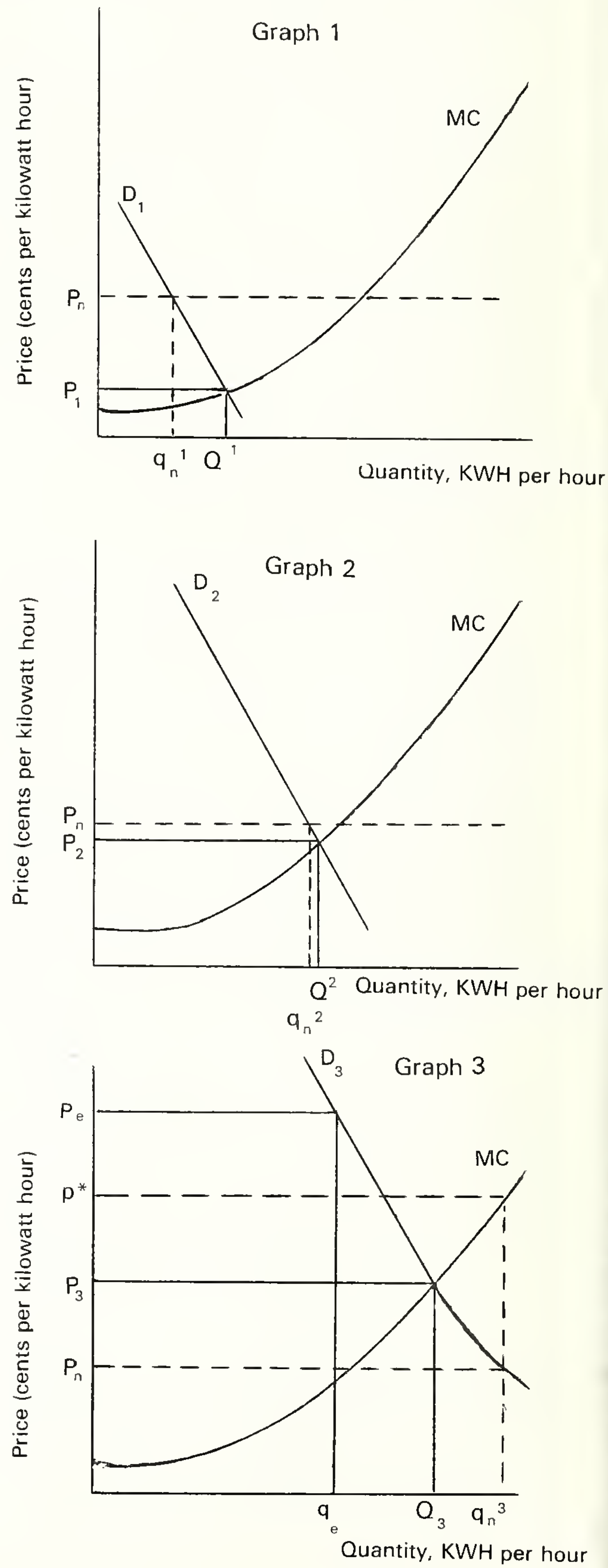


Table 1
Generating Capacity and Total Sales of Class A Electric Utility Companies in North Carolina
1970-1975

Generating Capacity[1] (KWH in 1000's)	1970	1971	1972	1973	1974	1975	Average Yearly Change
Duke	56,932,821	60,059,756	66,510,270	76,927,801	99,631,733	111,303,877	14.34
Vepco	46,147,680	48,013,560	55,179,240	67,162,920	74,889,240	81,035,130	11.92
CP&L	29,522,560	40,121,404	44,317,276	50,609,096	55,750,240	64,388,087	16.88
Nantahala	876,000	898,898	950,327	988,521	1,017,033	957,265	1.79
Total	133,479,061	149,093,618	166,957,113	195,688,338	231,288,246	257,684,359	14.06
Sales (including Resale)[2] (KWH in 1000's)							
Duke	35,287,995	36,912,737	39,688,068	43,158,623	42,343,600	42,137,670	3.61
Vepco	23,505,825	24,686,096	26,910,710	30,044,018	29,872,991	31,488,319	6.02
CP&L	17,547,500	19,656,673	22,101,472	24,081,319	24,076,446	24,118,233	6.57
Nantahala	374,735	415,173	414,278	445,685	474,269	412,891	1.96
Total	76,716,055	81,670,679	89,114,528	97,729,645	96,767,306	98,157,113	5.05
Ratio (Sales/Generating Capacity)							
Duke	.6198	.6146	.5967	.5610	.4250	.3786	
Vepco	.5094	.5141	.4877	.4473	.3989	.3886	
CP&L	.5944	.4899	.4987	.4758	.4319	.3746	
Nantahala	.4278	.4619	.4359	.4509	.4663	.4313	
Total	.5747	.5478	.5338	.4994	.4187	.3809	
Average Price[3] (¢/KWH)	1.34	1.43	1.49	1.60	2.04	2.65	

[1]Total installed KW capacity (FPC Form No. 1 p. 432-434) x 8760hours/year + KWH purchased (FPC Form No. 1 pg. 431, L. 10)

[2]FPC Form No. 1, p. 409, L. 12

[3]FPC Form No. 1, p. 409, L. 10, col. (b)/col(d): does not include resale

Figure 1 between 4 a.m. and 5 a.m., Graph (2), the demand between 10 a.m. and 11 a.m., and Graph (3), the demand between 5 p.m. and 6 p.m.

Under the present system, a customer is charged the same price per KWH whenever the electricity is used. The present average price is represented as Pn and was about 2.65 cents per KWH in 1975. At this price, consumers used q_n1 between 4 a.m. and 5 a.m. as shown in graph (1). Later in the day, they used q_n2 as shown in graph (2), and during the peak time with the price still at P_n consumers used $q_n{}^3$ as shown in Graph (3).

These same graphs also illustrate the effects of changing to a marginal cost, flat-rate (no block rates with variable time of day pricing) pricing system. A marginal cost pricing system would set prices equal to the marginal costs. Setting marginal cost prices consists of determining where the demand curve intersects the *MC* (marginal cost) curve in each diagram. An optimal set of prices is shown by P_1 in Graph (1), P_2 in Graph (2), and P_3 in Graph (3). Comparing the different prices, it is seen that the marginal cost price would be lower than the existing price at the times represented by Graph (1), and since the price was lower, people would use more electricity at this time, an increase from $q_n{}^1$ toQ^1. Much of this increase would come from people installing automatic timed switches on water heaters as is done in countries where time of day pricing is used.[6]

The price and quantity during the period represented by Graph (2) would be quite similar to the present for most residential users. The second big difference would occur during period (3). During this peak time, the electricity would be priced at its marginal cost instead of being subsidized. The price would be set at P_3. Because of the higher price, people would want to use less at this time and quantity would fall from $q_n{}^3$ to Q_3.

It is obvious that a substantial saving would be incurred. The people who now use $q_n{}^3$ of electricity at the time of peak do so because they are charged only P_n. However, the real cost of this electricity is p^*. The difference between these prices can be classified as a subsidy, financed by charging everyone more for their electricity at other times. The difference in these costs at different times of day increases as the system peak is reached,and has been estimated to vary by as much as from a low of about one cent per kwh at late night to over 11 cents per kwh at peak.*

Table 1 shows the relation between electric price and output and generating capacity. It was prepared by the office of Senator McNeill Smith whose bill established the hearings on electricity pricing.

The table shows that in the face of decreasing demand, utility companies have continued to expand generating capacity. Profits from electric utility companies are established as rates of return on capital base. This means that the more capital there is, the more profit there will be. But profit comes from higher electric rates.[7]

In 1970 Duke Power's ratio of output to capacity was 61.98%; by 1975 this had fallen to only 37.86%. This means that generating capacity has been increasing much faster than sales. As the percentage of excess capacity increases, the rate per kilowatthour increases.

Benefits

Possibly the largest savings from marginal cost pricing would be gained in the long run because the higher price and lower use at peak times could decrease the need for new construction. If some time in the future, some customers showed by their willingness to pay a high price at peak, that using electricity at the time of peak was worth to them as much as it cost to produce the electricity, then peaking plants could be added. But, they would be paid for only by the people using the electricity at the time of peak, rather than by all customers.

When marginal capital costs are included in the peak period marginal cost, the discrepancy between peak and off-peak costs becomes greater as the cost of generating plants increases. For example, Duke Power estimates the cost of its proposed Perkins nuclear plant at *more than* 632 dollars per kilowatt of generating capacity.[8] If a pricing system could eliminate or reduce the need for excess capacity then expensive construction programs could be eliminated at a great savings to the consumer.

A peak load pricing system should also provide benefits to lower income utility users. If a marginal cost pricing system was implemented in North Carolina, the total revenue collected by the utilities would be likely to exceed the total costs for production. To keep consumers bills equal to average generating costs, a rebate of the difference between the total revenue collected and the total cost should be offered to the customer. The rebate would be computed by determining the difference between the total revenue collected and the total costs of operating the system, and dividing this by the number of customers served. Since electricity use increases directly with income (Recent federal studies show an income elasticity of electricity use of about 1 by cross section.[9] Most studies show in time series analysis the income elasticity is about .5[10].), this would cause a relative decrease in the electric bills of low income people. Therefore, a peak load pricing scheme should have positive distributional effects.

**Differences this large probably only occur when a system is being used almost to capacity and the marginal capital cost of new construction are therefore included in the marginal cost calculation. At the present rate of utilization in the electric systems in North Carolina, the price difference would be much less because there is much unused capacity even at the times of peak usage.*

Why Three Instead of Two Prices?

With a peak-load pricing system, at least three prices are needed over a 24-hour period, plus one or two emergency prices. The time of highest price would be a three to four hour period during the heaviest demand. A second period would include most of the remaining waking hours and would be similar to the existing price. A third rate, for late night hours, would be much lower prices to reward off-peak users.

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During the hours of greatest demand and highest price, a consumer might choose to wait a few hours before turning up the air-conditioner, or save even more electricity by turning off his hot water heater. At off-peak hours when the price is very low, the customer might take advantage of the low rates by using a timer on his water heater, freezer, etc. Because time of summer peak coincides with the time when solar energy is most available, a peak pricing system would encourage development and use of solar technology.

A two price system is not considered appropriate because the object is to set prices that reflect marginal costs and the variation in marginal cost is so great that a two price system could only approximate the marginal cost part of the time. The rest of the time, the price would be either greater or less than marginal cost, and much of the present inefficiency would still persist with the addition of a more expensive metering system. A related problem is that if only two prices are used, the change in price from one to another must be substantial. Any sudden change in prices could cause a shift to the other side of the high priced period and shift the peak. A three or more price system is necessary so that changes from one price to the next can be sufficiently small. The optimal system would have very many prices. The use of three or four is a compromise between efficiency in pricing and the costs of metering.[11]

How should such a system be implemented? Inexpensive metering systems have been developed in Europe and could be used, or existing meters could be modified to provide multiple price capacity. In addition

Duke Power's McGuire Nuclear Generating Station is about 75 percent complete

Photo courtesy Duke Power Co.

to the three time of day prices, one or two emergency prices should be added. An emergency high rate would substitute for excess capacity. If a large plant broke down at a time of heavy use, the system would switch to an emergency rate such as the one shown as price= P^e on Figure 2, graph 3. As explained previously, the resulting difference between the power companies' total costs and the total revenue collected would be rebated equally to customers, so that only the people who used more than the average would wind up paying more. A low income, small user could conceivably wind up receiving a payment from the company instead of a bill at the end of the month.

What Choice . . .

In the long run, the choice facing consumers and Utility Commissions is between building new generating facilities or marginal cost pricing. As Carolina Power and Light said in an advertisement in the *Raleigh News and Observer*, ". . .the less you use at hours of peak demand, the less generating capacity we'll have to build. And the less your electric bill will have to go up in the future."[12]

After the decision is made to commit sums of capital for construction of new plants, all consumers of electricity are strapped with the economic burden. (Duke Power's proposed Perkins Nuclear Station will cost about three billion dollars, or the equivalent of the net worth of Duke Power's total assets in 1975.)

Many people seem confused by the concept behind peak load pricing. But, these same people have lived with peak load pricing for other commodities for most of their lives. The telephone company has special rates for time of day use to reward callers for using the lines during off-peak hours. This redistributes the demand for services. Without a marginal cost or time of day pricing system, the telephone customers would have no incentive to wait until evening to make calls. The telephone company would need to build more facilities and transmission lines to accomodate the peak hour demand,and the rates would have to increase to pay for building this "needed" new capacity.

Under an average pricing system, rates would skyrocket as the telephone company scrambled to keep up with a new construction program. Since the consumer would have no incentive to be selective of the time of day he phoned long distance, the wires would be flooded daily and the lines hopelessly tied up, resulting eventually in "ring out" (comparable to a brown or blackout). This would be followed by more construction programs and more rate increases.

There is no dispute among conservative or liberal economists that peak load or marginal cost pricing is the most efficient way to allocate any resource, including electricity. Marginal cost pricing is a method of pricing followed by electric utilities in nations around the globe. Marginal cost pricing is followed by business operations throughout the United States. It would seem such a system should be used by North Carolina utilities.

Footnotes

1. For a discussion of increasing costs and decreasing economies of scale, see: Leonard W. Weiss, "Antitrust in the Electric Power Industry," in *Promoting Competition in Regulated Markets,*. The Brookings Institution, Washington, D.C. 1975.
2. Federal Power Commission, *Form 1*, p. 409.
3. Duke Power Company and the Federal Power Commission, *Form 1*.
4. The traditional theory of peak load pricing is that the peak users pay the marginal capital cost as well as marginal operating costs. See Berlin, Cicchetti, and Gilen, *Energy Policy Project*, Chapter 3, 1974, also Alfred Kahn, "Between Theory and Practice", *Public Utilities Fortnightly*, January 2, 1975, pp. 29-33.
5. Paul L. Joskow and Martin L. Baugham, "The Future of the U.S. Nuclear Energy Industry", *Bell Journal of Economics*, Spring 1976, p. 17.
6. An extensive discussion of peak load pricing methods used in France and England appears in P. L. Joskow, et al., "Symposium on Peak Load Pricing", *Bell Journal of Economics*, 1976, pp. 197-240.
7. Commonly called the A-J effect, this phenomena is explained in Averich, H. and L. Johnson, "Behavior of the Firm under Regulatory Constraint", *American Economic Review*, December 1962.
8. United States Nuclear Regulatory Commission, *Final Environmental Impact Statement*, October 1975, Table 9.1
9. Bureau of Labor Statistics, *Consumer Expenditure Survey*.
10. Lester P. Taylor, "The Demand for Electricity: A Survey", *Bell Journal of Economics*, Spring, 1975, pp. 74-110.
11. A discussion of how to best allocate marginal capacity costs to prices at different time periods are discussed by John T. Wnders, "Peak Load Pricing in the Electric Utility Industry", *Bell Journal of Economics*, Spring 1976, pp. 232-241. He argues some marginal capacity costs should be included at all times.
12. Advertisement, *Raleigh News and Observer*, October 12, 1976.