Utility Rate Structure Design: Theory in Practice†

RICHARD S. BOWER and ROBERT J. ROHR*

Introduction

Dramatic changes in the electric utility industry have created problems for utilities, regulatory commissions and large segments of the public. The problems are associated with revenue instability, rising price per kilowatt hour and apparent discrimination among customer classes. The conventional declining block pricing structure contributes to each of these problems and does so because it presents customers with a set of prices that do not reflect the marginal cost of the service they receive.

This paper discusses the implementation of marginal cost based rate structures that provide utilities with required revenues as well as lead to an efficient use of society's resources. While the paper does not contain a new theory for pricing the output of regulated utilities, it does develop sound economic arguments for instituting and administering marginal cost pricing in practice. The pricing of electrical service is our main concern. However, many of the principles developed here apply in other regulated industries as well. Section II contains a brief review of marginal cost pricing and the difficulties which arise in its practical application to rate design. Section III deals with the inadequacies of the generally existing pricing policies followed by electric utilities. Finally, Section IV contains recommendations for using marginal cost pricing in rate-making. Further, we develop a rate structure for an operating utility and use it to illustrate our approach to rate design.

*Richard S. Bower is the Leon E. Williams Professor of Finance and Managerial Economics at the Amos Tuck School of Business Administration, Dartmouth College. Robert J. Rohr is Associate Professor of Economics, Brown University and Visiting Associate Professor of Economics at the Amos Tuck School.

†They thank Alan Schultz, Allan Martin, Esq., Professors D. M. Holthausen and A. O. Converse for suggestions and criticism. The authors also appreciate the assistance of Central Vermont Public Service Corporation, Rutland, Vermont, particularly Jonathan W. Booraem, Manager of Rates and Economic Research in providing data for the examples illustrated. Support for the research presented here was provided by the Tuck Associates Program and American Telephone and Telegraph Company. An earlier version of the paper was prepared for delivery at the Amos Tuck School of Business Administration Seminar on "Problems of Regulation and Public Utilities" sponsored by AT&T, August 25-29, 1974.

Marginal or Incremental Cost Pricing

Economists approach rate design with a view of achieving efficient allocation of society's resources. The method of doing this is traditional and well described by Alfred E. Kahn as "the central policy prescription of microeconomics . . . the equation of pricing and marginal cost."[1]

If the prices of all goods are set equal to marginal social costs of production, then, given the existing income distribution, society will achieve greatest efficiency with its limited resources. The concept of long-run marginal cost refers to the change in total cost associated with the smallest possible once-and-for all change in activity. It is not a concept that

[1]Kahn [7], p. 65.

applies easily to the addition of large blocks of capacity which involves discontinuities, indivisibilities, and a multi-time period adjustment sequence. In electric utilities, railroads, pipe lines, and the like,[2] these dynamic problems make the conventional concept of marginal costs only an imperfect approximation of the relevant decision variable.

Our estimate of the cost of adding a unit of capacity, which is itself an imperfect approximation, we term long-run incremental cost (*LRIC*). It is calculated by dividing the estimated annual cost of a new facility by its capacity.[3] Basic economic principles call for price equal to *LRIC*, but there are valid reasons for modifying this principle in practice. None of these reasons opposes the primacy of the marginal cost pricing principle. This point is argued very well in Baumol, et. al. [4]. We discuss several of the reasons for modifying *LRIC* pricing when we consider actual rate design and implementation in Section IV. At this point we address what has been the most important reason for deviating from *LRIC* pricing–the "revenue problem."

The revenue raised by utilities using *LRIC* prices is almost certain to vary from the revenue required to provide a fair rate of return on investment.[4] Some economists argue that this situation can be corrected by subsidizing those utilities with deficient revenues and taxing revenues from those with a surplus. The tax/subsidy solution to the revenue problem has not been accepted for two practical reasons. First, regulatory boards generally do not have, nor do they wish to have, the power to levy a general tax or provide a general subsidy; their business is regulation.[5] Second, if utilities with a revenue (deficiency) surplus are to be (subsidized) taxed the question arises as to (how the amount of subsidy is raised) how the tax revenue is to be spent.

Another solution to the revenue problem has been proposed by Baumol and Bradford [5]. According to their approach, utilities should (if possible) segment their markets and base rates on *LRIC* in each market. These rates are then adjusted in an inverse relationship to the elasticity of demand in these markets so that revenue requirements are exactly satisfied.[6] This proposal is supported not only by rigorous technical analysis but also by intuitively appealing idea that smaller welfare losses are associated with smaller movements from an optimum quantity position. As a practical matter, this theory of pricing, while very attractive, has not enjoyed broad acceptance. First, it is quite difficult to accurately estimate the elasticity of demand associated with various classes of service or markets. Secondly, those classes of customers that are charged more than *LRIC*

[2] Electric utilities must add capacity by building generation facilities which come in discrete (generally large) units and will be used to produce electricity on a continuing basis. The same applies to the other utilities mentioned. For a discussion in the case of railroads, see Baumol, et. al. [4].

[3] To avoid confusion at later points in the paper where we discuss fixed and variable costs, it should be pointed out that *LRIC* is an estimate of long-run marginal cost. We hope that the issue will not become confused with the economic axiom; in the long run all costs are variable. We also use the term embedded cost to refer to the historical cost of plant and equipment. It should be clear that embedded cost is generally not equal to replacement cost.

[4] If *LRIC* is above embedded cost and the regulatory board bases its revenue figure on these costs, then a rate structure based on *LRIC* will yield too much revenue. If *LRIC* is below embedded cost then a rate structure on *LRIC* will not raise enough revenue.

[5] Utilities as well as their customers complain about the long and expensive hearings associated with changes in rates. The final implementation would be further delayed if state legislatures had to approve taxes on some utilities and subsidies for others. Members of regulatory boards are under considerable political pressure under the existing arrangements and probably would not welcome the additional power to tax or subsidize.

[6] For example, if revenues are (deficient) excess and if the demand for residential electric service is determined to be relatively inelastic, then rates for this class of customers would be set (above) below *LRIC*. On the other hand, if the demand for industrial electric service is judged to be relatively elastic, then rates for this class should be set as close as possible to *LRIC*.

would have legal grounds to argue that the rates being charged them are discriminatory.[7]

The basic Baumol and Bradford approach to solving the "revenue problem" need not be abandoned completely. The problems referred to above do not arise if the Baumol and Bradford method is applied to elements of service rather than classes of customers. Elements of service for industries that must stand ready to serve can be identified as the customer cost, the cost of capacity, which depends on the quantity a firm stands ready to deliver, and the product cost, which varies with the units the firm actually does deliver. For example, the three *LRIC* elements of an electric utility would be associated with serving one more customer, having one more kilowatt of capacity available, and delivering one more kilowatt hour of energy. If three part tariffs are set on an *LRIC* basis and revenue is either insufficient or in excess, it should be the customer part of the tariff that is adjusted to meet the revenue requirements. Adjustment of the customer charge should have no impact on demand for capacity or on the units of service delivered unless that charge exceeds the consumer surplus of some set of customers. Although this may be the case for some small number of customers, the response to a change in customer charge should be very slight.[8] The demand for the element of service that makes the customer part of the system is, in other words, very inelastic. By adjusting the customer charge to satisfy revenue requirements, the problem of elasticity estimation across classes and of price discrimination are avoided. Using the customer charge as the residual price, insures that all classes of customers deviate from the *LRIC* of this element of service by the same percentage. This transforms the three-part tariff from a theoretical target to a practical proposal.

Traditional Electric Utility Rate Design

The traditional structures used in the electric utility industry contribute to the industry's present problems. Until quite recently, public utility commissions were primarily concerned with the total dollars that a utility should be allowed to raise and considered the structure of rates only in terms of revenue realization and customer claims of discrimination.[9] Consequently, a public policy concerning electric utility rate design and the impact it would have on the scarce resources of society has not been established. This is not to suggest, however, that electric utilities were not cognizant of costs when designing rates. Cost relationships have always been a consideration in designing a value of service rate structure.

The decreasing block rate structure offered residential customers is an example of this. Because the system requires a minimal distribution grid that depends on customer location and because customers require meters, meter reading and billing regardless of the number of kilowatt-hours they consume, it seemed clear that average cost per kilowatt-hour would fall as average consumption per customer increased. Recognizing this, believing that larger users have better load factors,[10] and considering that the value of service falls[11] as a customer ex-

[7] The discriminatory tariff argument had more weight in the recent past when *LRIC* was below embedded cost, so that *LRIC* pricing would result in a revenue deficiency. This objection may now be academic, for the electric utility industry at least, since *LRIC* appears to be generally above embedded cost.

[8] We are assuming that the demand for having the ability to achieve service is relatively inelastic. However, if the customer charge were to be substantially above *LRIC* some consumers may find it advantageous to generate their own electricity.

[9] This was generally the case in all requested industries, the notable exception being the transportation industry.

[10] Load factor is a measure of capacity utilization and is computed by dividing KWH per period by potential KWH per period.

[11] The concept of value of service in rate design refers to the fact that electricity tends to have the same use value to a customer whether consumed on or off-peak. This does not obviously apply to off-peak use during the middle of the night.

tends his use of electricity, rate makers quite naturally came to declining block structures. The structure below is typical.[12]

Monthly Billing

First 20 KWH or less per month $2.75
Next 120 KWH per month @ 3.00¢ per KWH
Next 360 KWH per month @ 2.45¢ per KWH
All over 500 KWH per month @ 2.30¢ per KWH

The declining block rate structure is invariant to time of day or season of use and therefore tends to under-price consumption at system peak and over-price consumption at other times. This distortion leads residential customers to over-consume during potential peak periods and under-consume during off-peak periods. Further, since the customer is billed only on monthly KWH usage, he has no financial incentive not to run all appliances simultaneously during potential peak periods.[13] The type of customer behavior that is encouraged by this rate structure was inadvertently put into the record in a recent Vermont rate case (Central Vermont Public Service Corporation, Docket #3744). This type of information is unusual because it is developed from actual KWH use recorded by a set of representative residential customers. Studies of this detail for individual residential customers are not often done and when done are not usually published. That is why the observations shown in Table 1 are so worthwhile as an illustration. Those observations indicate the annual KWH use and maximum KW demand of ten residential customers on an actual operating system.[14]

TABLE 1

Customer Number	*Maximum KW*	*Annual KWH*	*Annual Bill*
7101	4.96	4736	$151.07
7102	5.66	3344	116.97
7103	5.04	7372	213.76
7104	2.61	3892	130.39
7105	3.99	12624	334.22
7106	2.23	2844	104.72
7107	3.77	7004	205.09
7108	5.95	5218	162.72
7109	1.93	3292	115.69
7110	3.73	5691	173.96

If the individual peaks recorded during the metered hours all have an equal likelihood of occurring at the system peak, then the capacity cost of serving these customers will vary in approximate proportion to their meter readings. The cost associated with each unit of capacity recorded at a customer's peak during the metered hours will reflect the cost of adding another KW of capacity to the system and the diversity implied by the ratio of the class peak to the sum of recorded customer's peaks. Since customer #7102 demands 193 percent more capacity than customer #7109 and only slightly more energy, the cost of serving customer #7102 would be about 200 percent more than that of customer #7109. Column 4 of the table clearly illustrates the inequities that can arise when customers are not metered and billed according to time of day use. Under the decreasing block rate structure illustrated above customer #7102 pays an annual bill of only one percent more than customer #7109, inspite of the substantial difference in the cost of serving him.

Electric utilities have recognized that off-peak users cost less to serve and have offered off-peak rates, such as hot water heating. However, the rates for this service are generally set by the average cost of serving a customer and are above the cost of actually providing that service. Thus, we again find that existing utility rate structures encourage the uneconomic use of electricity. What is more, in many instances the tail block is lower than the off-peak rate, encouraging the big user not to move his, easily transferred, use out of potential peak periods and inviting him to pass up off-peak options.

Electric utilities have used peak load pricing on large commercial and industrial customers. These customers are billed on either a two part (demand and energy) or a three part (customer, demand, and energy) tariff. The customer charge reflects the average cost of being attached to the system. The demand charge is intended to reflect the average cost of capacity that the utility is required to maintain in order to be ready to serve the customer. The energy charge reflects the average cost of operating the capacity to produce a KWH of electricity. The demand charge is usually computed from the maximum KW load per customer for a month. Thus, the demand charge is based on a customer's own maximum KW load (non coincident peak) and need not indicate the requirement he places on system capacity.[15]

The non-coincident peak demand charge is superior to a straight KWH charge because of the incentive it provides for load factor improvement. Even with this virtue, it involves the same problems we described in discussing residential declining block structures. If all customers in a rate class with this structure are not equally likely to draw their maximum load on the system peak, then this system will discriminate against those less likely to impact system peak and in favor of those more likely to do so. Even if all customers are equally likely to draw their maximum load on the system peak, this structure does not provide a financial[16] incentive for a customer to shift his load out of potential peak periods. This incentive is provided only when the customer is metered during potential peak periods and charged the *LRIC* of capacity for his contribution to system peak.[17] Further, utilities generally have encouraged peak consumption by pricing capacity below average historical embedded cost, making up the revenue by pricing energy above the average cost per KWH.

The above discussion clearly illustrates how the pricing policies of electric utilities contribute to present problems. Again, this is the result of not charging more for on-peak than off-peak consumption of capacity, combined with the fact that the *LRIC* of capacity is well above the average embedded cost. Electric utility executives generally do not accept this argument, but attribute the present state of affairs to the industry reaching a point where costs increase with time and scale, rather than decrease. It is easy to agree that inflation and a slower rate of innovation make the cost of added capacity more likely to increase with time and make the incremental cost of capacity more likely to be above embedded cost. It is not so easy to agree that scale economies, in the static economic sense, are more completely exhausted today than they were a decade or two ago. And it is very difficult to overlook the fact that kilowatt-hours generated by capacity large enough to serve an unrestrained peak

[12]This rate structure was supplied by Central Vermont Public Service Corporation, Rutland, Vermont.

[13]For example, suppose a residential customer has three appliances which draw five kilowatts and run for an hour. Since the customer is only billed for KWH, it makes no immediate dollar difference to him if he runs all three at once, placing a load of 15 KW on the system, or runs them sequently placing a load of only five KW on the system. However, the costs to the utility are obviously much greater if this customer were to draw 15 KW rather than five KW on system peak.

[14]The maximum KW reading was recorded from 5 to 8 P.M., a period when the system peak is likely to occur. This does not mean, however, that these recordings were recorded at system peak. The data was supplied by Central Vermont Public Service Corporation.

[15]The demand meter would only reflect a customer's share in the capacity of the system if his peak coincided with the system peak.

[16]If a customer's peak is coincident with system peak and forces the utility to add capacity above embedded cost per KW, then his bill will eventually reflect higher demand charges per KW.

[17]The demand charge per KW is usually computed by dividing the cost of system peak KW responsibility by the sum of the non-coincident recorded peaks. The demand charge would reflect the peak cost responsibility only if all customer recorded peaks were coincident with the system peak or if all customers were equally likely to draw the maximum load at system peak.

must cost more than kilowatt-hours generated by a more evenly loaded system. It is this last relationship that industry pricing practices have always ignored and, with inflation and a slower rate of innovation, this relationship has become the sellers' as well as the buyers' problem.

According to the Averch-Johnson [2] hypothesis, rate of return regulation encourages utilities to invest in excessive amounts of capital. A widespread interpretation of this theory holds that utilities would expand their invested capital and thus their return by excessive capital use and gold plating. Although electric utilities may have adapted the above policies to expand rate base, our analysis strongly suggests that their rate structures have been the most important factor in promoting unnecessary capital investment. By underpricing consumption at system peak, electric utilities have encouraged capacity growth in a manner consistent with the Averch-Johnson hypothesis. We do not claim that electric utility executives knowingly designed rate structures that would permit excess use of capital. What we do suggest is that pricing below cost at the peak and above cost off the peak found acceptance because it had congenial results for the companies and did not arouse the other parties to regulation. The rising rate base it created sheltered increasing profits for the companies and neither prevented rates from falling for customers nor created conflicts for Commissions.

Incremental Cost Pricing

It is essential for electric utilities to design rate structures that reflect *LRIC*. Structures of this type are possible and practical, and this final section is an application for an operating electric utility.

The rate structure we propose is based on approximate incremental costs and consists of three parts; a customer charge, an energy charge and a peak capacity charge.[18] The introduction of a peak capacity charge requires an estimate of each customer's contribution to system peak. A simple means to achieve this estimate is by the use of timed demand (KW) meters.[19] In the past it may have been difficult to cost justify the installation of such meters, particularly on residences. However, with the cost of electric service increasing by as much as 50 percent in some areas, the installation of timed demand meters can no longer be rejected as uneconomic.[20]

The customer charge is based on the approximate incremental cost of adding a customer to the system. This cost can be estimated from historical data on customer accounting, customer services, meter operation, direct services, transformer maintenance expenses, and return on meters and transformers. The incremental cost of adding a customer within the system's existing geographic boundaries will be well below the average embedded cost per customer. The basic delivery system is a very large embedded common cost associated with all customers but not incremental to any single customer. This is illustrated in *Table 2* which contains the actual average embedded customer cost as computed by Central Vermont Public Service Corporation (CV). Table 3 contains our calculation of the estimated incremental cost of adding a customer to CV's system.

The approach which supports this calculation of incremental customer cost and the calculations for capacity and energy cost as well can be summarized very simply. It is

$$IC_j = DOC_j/N_j + (RB_j * RR)/N_j$$

where IC_j = the incremental cost per unit peryear of the service element j, j being customer, energy or capacity;

DOC_j = the direct operating cost, including depreciation expense, of the service element j;

N_j = The total units appropriate to service element j, i.e. number of customers, KWH or KW;

RB_j = The rate base directly attributable to service element j; and

RR = the allowed rate of return.

[18] The two-part tariff is generally credited to the English engineer John Hopkinson who introduced demand and energy charges in 1882.

[19] Our colleague Professor A. O. Converse of the Thayer School, Dartmouth College, proposes timed KWH meters to estimate a customer's contribution to system peak. We are not in a position to debate one type of hardware as opposed to another. The important objective is to obtain a good estimate of contribution to system peak and charge accordingly.

[20] The cost of a 10 hour spring backed timed demand meter would add about $1 per month to a customer's bill over the 25 year life of the devise.

TABLE 2
Central Vermont Public Service Corporation
Analysis of Customer Costs

	Residential	*General Service*	*Primary Service*	*Transmission Service*
Expenses:				
Customer Accounting	$ 854,355	$ 342,479	$ 47,376	$ 3,339
Customer Service	170,779	57,079	64,231	8,852
Meter O. & M.	166,426	66,448	26,568	2,696
Services O. & M.	11,726	2,066	–	–
Transformer O. & M.	19,778	2,657	–	–
Secondary Lines	210,015	28,219	–	–
Primary Lines	947,807	132,072	2,433	–
Attrition	270,373	45,890	4,426	418
Rate Case Expense	124,245	44,795	46,631	9,621
Depreciation Expense	462,606	79,085	7,818	742
Taxes Excluding Income	737,264	131,503	14,946	1,458
Miscellaneous Revenue Credit	(175,947)	(24,287)	(374)	9
Income Taxes	148,696	95,212	6,704	26
Return @ 9%	1,663,270	280,944	26,499	2,289
Customer Costs	5,611,393	1,284,162	247,258	29,450
Number of Customers	77,500	10,795	190	11
$/Customer/Year	$72.40	$118.96	$1,301.36	$2,677.27
$/Customer/Month	$ 6.03	$ 9.91	$ 108.45	$ 223.11
Rate Base (Customer):				
Meter	$ 1,879,920	$ 750,598	$300,110	$30,458
Services	3,741,174	659,203	–	–
Transformers	3,545,865	476,454	–	–
Secondary Lines	1,846,474	248,108	–	–
Primary Lines	8,333,192	1,161,194	21,291	–
General & Intangible	455,429	77,512	7,567	717
Projected Additions	769,966	131,044	12,795	1,212
Construction Work in Progress	346,505	49,292	1,588	94
Acquisition Adjustment	3,050	519	50	5
Customer Plant in Service	20,921,575	3,553,924	343,401	32,486
Accumulated Provisions for Depreciation	2,833,724	484,393	47,869	4,545
Net Utility Plant	18,087,851	3,069,531	295,532	27,941
Contributions in Aid	380,025	103,133	25,498	–
Working Capital	772,961	155,206	24,395	2,511
Customer Rate Base	18,480,787	3,121,604	294,429	25,430

TABLE 3
Determination of Incremental Customer Costs

	Residential 1	*General Service*	*Primary Service*	*Transmission Service*
Accounting	$ 854,355	$ 342,479	$ 47,376	$ 3,339
Service	170,779	57,079	64,231	8,852
Meter O & M	166,426	66,448	26,568	2,696
Services O & M	11,726	2,066		
Transformer O & M	19,778	2,657		
Total Customer Costs	1,223,064	470,722	138,175	14,883
Total Customers	76,890	10,684	191	11
$/customer/year	15.91	44.06	723.43	1,353
$/customer/month	1.33	3.67	60.28	112.75
Rate Base Items				
Meters	1,879,920	750,598	300,100	30,458
Transformers	3,545,865	476,454		
	5,425,785	1,227,052	300,100	30,458
Return @ 8.5%	461,192	104,299	25,509	2,589
$/customer/year	6.00	9.76	133.56	235.36
$/customer/month	.50	.81	11.13	19.61
Total customer/month	1.83	4.48	71.41	132.36
Customer Charge	2.00	4.50	75.00	135.00
Demand meter cost	1.00	1.00		
Proposed customer charge	3.00	5.50	75.00	135.00

The simplicity of the approach should not obscure the complexity and imprecision of the actual estimates made from cost accounting data and engineering analysis.

The incremental cost of providing an additional KWH is partially determined from the average energy cost[21] of existing generation and/or purchase power contracts. This estimate combined with a purchase energy and fuel adjustment clause will provide prices which closely approximate the incremental fuel cost of generating an additional KWH of energy. Table 4 illustrates the average cost per KWH of energy for CV.

The incremental cost of capacity consists of the incremental cost of production and transmission. The incremental cost of production can be determined from engineering estimates for adding future capacity in some specified mix, i.e. 50 percent base load nuclear, 30 percent intermediate and 20 percent peaking plants. The incremental cost of transmission can be estimated in a similar manner or from historical cost data on transmission and distribution expenses and return on the associated rate base items. Our estimate of incremental capacity cost per customer class, based on CV data, is given in *Table 5.*

The incremental energy charge should just about cover the producer's actual energy cost and required return on energy related assets. Few costs involved with energy are embedded, and almost all change immediately with KWH consumption. The incrementally determined capacity charge should provide more revenue than is required for a fair return on capacity related assets. Inflation seems to overwhelm scale opportunities and technological improvements, leaving the incremental cost of capacity well above the average embedded cost. This is clear when one compares the embedded cost of CV capacity given in *Table 6* with the incremental cost of capacity in *Table 5.* The excess revenue raised by an incrementally based capacity charge is offset, at least in part, by the customer charge situation. If the offset is not exact we do not propose a government tax or subsidy, or adjustment of rates to reflect the relative demand elasticity in different markets. Instead, we recommend adjustment of the customer charge so that the combination of energy, capacity, and customer charges would raise just enough revenue to cover allowable expenses and a fair rate of return. Treating the customer charge as the residual is practically and theoretically sound, since customer decisions on energy and capacity use are not affected by this charge. The decision to take or not take electric service should be relatively unresponsive[22] to deviations of this charge from *LRIC.*

As mentioned previously, the billing of peak capacity costs requires an estimate of each customer's probable contribution to system peak. Recognizing the infeasibility and impropriety of recording every customer's KW load at system peak, we propose that each customer's maximum load be recorded during

21 We recognize that the cost of energy may vary with time of day or season. Thus, a better estimate of incremental energy costs would be a rate structure with timed KWH charges. However, we do not feel that the relative costs involved warrant the implementation of such a structure at this time.

TABLE 4
Central Vermont Public Service Corporation
Analysis of Energy Costs

	Residential	*General Service*	*Primary Service*	*Transmission Service*
Expenses:				
Power Supply–Energy	$1,514,655	$1,094,008	$1,550,223	$417,415
Depreciation Expense	6,178	12,554	17,788	4,790
Attrition Expense	7,688	4,110	6,133	1,597
Taxes Excluding Income	11,879	21,976	31,141	8,386
Miscellaneous Revenue Credit	(20,868)	(42,381)	(60,054)	(16,170)
Income Taxes	2,213	12,574	13,301	163
Return	24,749	37,101	52,572	14,156
Energy Costs	1,546,494	1,139,942	1,611,104	430,337
MWH at Meter	430,000	238,000	350,000	98,000
Mills/Kwh	3.60	4.79	4.60	4.39
Rate Base:				
Power Supply	$221,934	$450,747	$638,714	$171,981
General & Intangible	5,433	11,034	15,634	4,210
Projected Additions	8,839	17,950	25,435	6,849
Construction Work in Progress	2,245	4,561	6,462	1,740
Energy Plant in Service	238,451	484,292	686,245	184,780
Less:				
Accumulated Provisions for Depreciation	89,189	181,140	256,678	69,113
Net Utility Plant	$149,262	$303,152	$429,567	$115,667
Working Capital	$125,730	$109,082	$154,570	$ 41,620
Energy Rate Base	$274,992	$412,234	$584,137	$157,287

22 A customer will not respond to the charge at all as it moves between zero and the full amount of his consumer surplus from electricity use. That surplus is the sum of how much extra he would pay for the KW and KWH for each of his uses of electricity, from the most to the least vital, than he is being charged for those inputs.

TABLE 5
Determination of Incremental Capacity Cost

1. *Production*

50% Nuclear @ $99/year/KW		$49.50
50% Fossil @ $62/year/KW		31.00
		$80.50

2. *Transmission and Distribution*

	Residential	*General Service*	*Primary Service*	*Transmission Service*
Transmission	$ 931,000	$ 636,000	$ 617,000	$ 171,000
Distribution	868,000	374,000	332,000	3,000
Total	$1,799,000	$1,010,000	$ 949,000	$ 174,000
Rate Base	20,739,000	10,410,000	9,400,000	1,618,000
Return @ 8.5%	1,763,000	885,000	799,000	138,000
Total	3,562,000	1,895,000	1,748,000	312,000
Peak MW	132	56	54	15
$/KW/year	$26.98	$33.84	$32.37	$20.80
3. *Capacity Cost Per Class*				
$/KW/Year	$107.48	$114.34	$112.87	$101.30
$/KW/Month	8.96	9.53	9.41	8.44
Round to	9.00	9.50	9.50	8.50

4. *PASNY Capacity Cost for Residential Only*

58 MW @	$28.44/KW/Year
T&D @	26.98/KW/Year
	$55.42/KW/Year
	$ 4.62/KW/Month
Round to	$ 4.50/KW/Month

periods of potential system peak, say from 5 to 8 P.M. During the above metering period, many customers will record a peak load at times other than system peak. Thus, to estimate a customer's contribution to system peak, the probability of his drawing the metered load at system peak is necessary. That is, the KW responsibility for a customer is

KW (responsibility) = KW (metered)
X Probability of drawing this load at system peak.

An estimate of this probability is obtained from the ratio of class coincident peak[23] to the sum of customer recorded peaks, e.g.

$$\hat{p} = \frac{\text{class coincident peak}}{\text{sum of recorded peaks}}.$$

This probability estimate is the diversity referred to above. To the extent that each of the hours being recorded has an equal chance of being the peak hour, although only one will be in fact, this approach does not unfairly penalize any customer. While the event that a customer draws his maximum load at system peak is random, it should be recognized that all metered hours and all days are not equally

[23]We use the term *class coincident peak* to refer to the contribution of a class to system peak. The term *class peak* refers to the peak load of a class, which may or may not be equivalent to the class coincident peak. The *non-coincident peak* is the sum of the customer peaks for a class of service.

TABLE 6
Central Vermont Public Service Corporation
Analysis of Capacity Costs

	Residential	*General Service*	*Primary Service*	*Transmission Service*
Expenses:				
Power Supply–Production	$ 5,924,469	$ 3,161,236	$ 3,048,570	$ 856,864
Transmission	931,469	636,020	616,597	171,325
Distribution:				
Substations	129,072	62,847	69,320	2,847
Primary Lines	523,340	256,572	262,650	–
Secondary Lines	201,908	49,722	–	–
Line Transformers	13,427	3,751	–	–
Services	890	219	–	–
Research and Development	58,328	27,944	24,657	3,699
Attrition Expense	351,188	185,960	169,161	32,736
Depreciation Expense	468,037	238,750	211,630	35,507
Taxes Excl. Income	689,337	328,075	290,443	43,394
Miscellaneous Revenue Credit	(297,354)	(177,559)	(174,783)	(35,110)
Income Taxes	194,305	393,085	268,450	2,370
Return	2,173,434	1,159,886	1,061,067	206,063
Capacity Costs	$11,361,850	$ 6,326,508	$ 5,847,762	$1,319,695
NCP KW at Meter	304,122	94,739	91,907	18,380
$/KW/Year	$37.35	$64.73	$63.63	$71.80
$/KW/Month	$ 3.11	$ 5.39	$ 5.30	$ 5.98
Rate Base (Demand):				
Power Supply–Production	$ 3,410,389	$ 2,477,936	$ 2,389,623	$ 671,653
Transmission	3,548,108	1,763,561	1,771,849	454,576
Other Investments–Nuclear & Velco	6,997,964	4,786,893	4,616,289	1,297,503
Distribution				
Substations	2,660,712	1,295,532	1,428,975	58,703
Primary Lines	4,601,252	2,235,979	2,309,145	–
Secondary Lines	1,775,218	437,164	–	–
Transformers	2,407,239	672,614	–	–
Services	283,897	69,913	–	–
General & Intangible	441,876	212,194	187,349	28,285
Projected Additions	743,691	356,296	314,385	47,157
Construction Work in Progress	596,201	281,181	268,310	33,004
Acquisition Adjustment	1,892	761	602	–
Capacity Related Plant in Service	$27,468,439	$14,590,024	$13,286,527	$2,590,881
Less: Accumulated Provision for Depreciation	3,973,920	2,115,019	1,969,422	400,951
Contributions in Aid	462,229	125,442	31,013	–
Working Capital	1,116,976	538,056	503,541	99,659
Capacity Rate Base	$24,149,266	$12,887,619	$11,789,633	$2,289,589

likely. Further, the probability associated with a customer is not independent of other customers. This covariance results from the influence of exogenous factors, such as the weather, on the joint probability distribution function.

Using our method, a customer's estimated contribution to system peak is not only a function of his use patterns, but is also a function of the use patterns of all other customers in his class. A customer's estimated contribution to system peak would change if the class diversity factor changed, and his recorded demand remained constant. For example, suppose a customer drew 10 KW during peak hours in January. Further, suppose at system peak the class coincident peak is 100 MW and the sum of recorded peaks is 200 MW (these peaks need not have occurred in January, but only some month included in the measurement band). This customer would have a peak capacity responsibility of

$$5 \text{ KW} = \frac{10 \text{ KW} \times 100 \text{ MW}}{200 \text{ MW}}$$

If the system were to reach a new peak in March with a class coincident peak of 120 MW and a non-coincident peak of 220 MW, the customer would then be responsible for a

$$5.45 \text{ KW} = \frac{10 \text{ KW} \times 120 \text{ MW}}{220 \text{ MW}}$$

contribution to system peak.

The proposed rate form provides customers the opportunity to reduce their future KWH cost by adjusting their use patterns if they so desire. Under a system which bases the monthly bill only on KWH usage, the customer does not realize the impact his behavioral patterns have on utility cost and ultimately his cost. Since the cost of providing a unit of capacity is many times the cost of providing a unit of energy, it is essential that customers be informed of this cost by means of a peak period capacity charge. The institution of our rate form will accomplish this as well as induce customers to limit their demand for capacity. We expect this change in consumer behavior to take place gradually and involve not only rate payers but also contractors and producers of electricity-using equipment and control devices. A first reaction simply may be the spreading of use to off-peak hours. For residential customers, this may involve changing the times when dryers are run and ovens cleaned. Commercial customers may alter their operating hours or move postponable activities to the middle of the night. Industrial customers may choose to stagger their employees' working hours or generate their own electricity during potential peak periods. This reaction may be fairly substantial for all classes of customers. Recent price increases for electrical service have raised the share of a residential customer's income spent on this commodity and have increased operating expenses for commercial and industrial operations.

A second reaction may be a shift in the mix of appliances and equipment used by rate payers. In new homes, devices with a heavy KW requirement for a short period may be installed less frequently. In existing establishments, the same may be true for replacements. For example, fewer vacation homes may be all electric and more replacement stoves may be gas stoves. A third reaction, and the most important one, should be the introduction of new devices to limit KW loads for particular pieces of electric equipment and for a rate payer's overall use of electricity.

An approximate incremental cost rate structure we designed for Central Vermont Public Service Corporation is given in *Table 7*. The capacity charge is computed from the estimate of a customer's contribution to system peak described above. The charge is based on the highest recorded demand for the last 12 months and the diversity factor at system peak. For example, the customer who drew 10 KW in January would be billed on the basis of 5 KW for the next 12 months or (a) until a higher than 10 KW load is recorded on his meter or (b) a new system peak is determined.

At the time the proposed structure was designed, only a few of the largest customers were time of day demand metered. Consequently, there was little hard data on the relationship between the class coincident peak and the sum of recorded peaks during potential peak periods. Lacking this information, we felt that the company, as well as its customers, should be protected by specification of these respective values as part of the rate design. However, once all customers in a class are demand metered, these magnitudes should be dropped from the rate schedules.

The inclusion of magnitudes for diversity factor computation as part of the rate design is best illustrated by the residential class of service. For this class, a customer's contribution to coincident peak is presently estimated from KWH use and load factor relationships. Since load factors are not invariant to rate structure change and since we expect load factors to improve under the proposed rate structure, it is difficult, if not impossible, to predict the affect on diversity factor of peak capacity pricing. Given the impact the diversity factor has on the company's ability to raise its allowed revenue, it is important that diversity factor be considered an integral part of the rate design. Further, since timed demand meters cannot be instantaneously installed on all customers in a class, many must be billed on the basis of estimated KW draw until their meters are operative. To complete the rate structure, we have specified a non-coincident peak (during peak hours) base of 160 MW. This value is not forever fixed, but changes as more and more customers are metered, eventually reaching a meter determined value. For example, suppose the KW non-coincident peak estimate for the first group of metered customers is 30 MW, but 40 MW are recorded. The non-coincident peak for use in computing the diversity factor would then be 170 MW.

The coincident peak for billing would remain at 132 MW until all customers of the class are metered or until a new higher coincident peak is established. If existing customers respond as expected, they will shift load out of peak periods and reduce the class coincident peak below 132 MW. However, during the transition period, the class capacity charge will not be changed to reflect shifting. Individuals of the class could benefit by load shifting at the ex-

TABLE 7
Proposed Rate Design

Monthly Rates

Residential

Customer Charge:	\$3.60 (\$2.60 + \$1 Demand Meter)
Capacity:	First .75 KW @ \$4.50/KW Above .75 KW @ \$9.00/KW
Energy:	.5¢ per KWH

The company shall use a 160 MW basis for non-coincident peak and bill a minimum of 132 MW coincident peak until all customers in the class are demand metered.

General Service

Customer Charge:	\$6.60 (\$5.60 + \$1 Demand Meter)
Capacity:	\$9.50/KW
Energy:	.5¢ per KWH

The company shall use a 67 MW basis for non-coincident peak and bill a minimum of 56 MW coincident peak until all customers in the class are demand metered.

Primary Service

Customer Charge:	\$90.00
Capacity:	\$9.50/KW
Energy:	.5¢ per KWH

The company shall use 54 MW for purposes of billing capacity charges with a diversity factor of 1.

Transmission Service

Customer Charge:	\$162.00
Capacity:	\$8.50/KW
Energy:	.5¢/KWH

The company shall use 15 MW for purposes of billing capacity charges with a diversity factor of 1.

pense of other existing customers. A customer could also benefit when new members are added to the class. This would occur if new customers did not raise the recorded peak above 132 MW, but increased the non-coincident peak. We expect customer growth within a class will allow all customers of the class to benefit from efforts to move off peak. The transition period portion of the rate design provides the company with revenue stability and time to adjust capacity in light of improved information concerning its customers' capacity requirements.[24] After transition, the benefits of peak leveling will go to the customers.

There exists the possibility that customer attempts to move off peak will cause the peak to shift to a new unmetered period rather than to level. This could lead to a new higher system peak for a company like CV, if residential customers moved a bulk of their load to say 4 P.M. The residential load added to the commercial and industrial load at that time could result in a peak higher than the previous 6 P.M. system peak. While we recognize this possibility, we do not feel it is very likely in the short run. The residential load is to a large extent determined by working hours, dinner hours, and day-light hours. We do not feel that residential customers will respond to the proposed rate structure with an immediate change in life style, e.g. cooking the evening meal at 4 P.M. Adjustments in working hours, life styles, appliance mix, etc. take time. If utilities, through their monitoring of daily system load detect a potential time shift in peak, the hours of peak period metering could be changed before the next peaking season. Because of this, it must be made clear to all customers that what they are buying is not low rates in particular hours, but low rates in hours that are off-peak.

Revenue estimates computed from the *LRIC* customer charges given in Table 3, the *LRIC* capacity charges given in Table 5, and a *LRIC* energy charge of .5¢/KWH are given in Table 8. Using these costs as prices yields a revenue deficiency of $733,000. The calculation required to adjust the customer charge per class of service to make up this revenue deficiency is given in Table 8. The rates given in Table 7 are approximately incrementally cost based in that the customer portion required upward adjustment from *LRIC* to provide the company with sufficient revenue.

In the second section of this paper we mentioned that there are a number of practical reasons for deviating from *LRIC* pricing. One modification is pricing the first .75 KW of residential capacity at $4.50 a month, a value below the *LRIC*. This was done to recognize the long term purchase, by the State of Vermont, of a large block of hydro power, from the Power Authority State of New York, for the exclusive use of residential customers. Thus, the first .75 KW of capacity per residential customer is based on embedded rather than *LRIC*.

Another modification would be applied to individual customers for the purpose of providing bill stability. The transition from existing rate schedules to an incremental cost schedule would have to be introduced with a limitation on the amount of yearly increase that an individual customer could be billed if his KWH usage were constant. For example, customer #7102 would face an increase of about 400 percent if our incremental cost rate structure were imposed immediately and his use pattern of KW did not change. We suggest that the increase for any customer be limited to 50 percent in any year, but his statement contains the amount his bill would eventually reach if his use patterns remain constant.

Final Comment

It seems to be a condition of membership in the economics profession that you affirm sup-

[24] The company will obtain better and better load factor information as more and more demand meters are installed on its customers. By the time all customers are demand metered, there should be very good information available on load factor relationships.

TABLE 8
Revenue Required and Raised

1. *Required Revenue* $35,226,000
2. *Revenue Raised by LRIC (x000)*

	Residential	*General Service*	*Primary Service*	*Transmission Service*	*Total*
Customer	$ 2,768	$ 705	$ 172	$ 18	$ 3,663
Demand	11,088	6,432	6,156	1,530	25,206
Energy	2,150	1,183	1,801	490	5,624
	$16,006	$8,320	$8,129	$2,038	$34,493

3. *Revenue Deficiency* $733,000
4. *Customer Charge Adjustment*

	Residential	*General Service*	*Primary Service*	*Transmission Service*	*Total*
Charge	$ 3.00	$ 5.50	$75.00	$135.00	
Factor	1	1.83	25	45	
Customers Adjust.	76,890	19,552	4,775	495	101,712

Adjustment per Adjusted Customer = $7.21/year; $.60/month

5. *Adjusted Customer Charge per Month*

	Adjustment	*Charge*
Residential	$ .60	$ 3.60
General Service	1.10	6.60
Primary Service	15.00	90.00
Transmission Service	27.00	162.00

port for marginal cost pricing. Inspite of this, marginal cost pricing has not been the rule among regulated firms. The reason for this is not only the past structures of regulated industries, but also the problem of placing the theoretical analysis in the proper technological/institutional setting. We have looked at the theory with this in mind, and found that it can be placed in the current setting of regulation. We have examined the existing pricing structures and discovered that their unhappy effects provide good reason for placing theory into use. And we have provided a simple, specific, realistic example of the application of marginal cost theory in a current rate case. If commissions and companies find that the theory fits the current requirements, and we believe that they will, then just as Keynes suggested[25] "practical men, who believe themselves to be quite exempt from any intellectual influences, [may become] the slaves of some defunct economists."

[25] See Keynes [13], p. 383.

References

[1] Armstead, H. C. H., Electricity Costs and Tariffs: *A General Study*, New York, United Nations, 1972.

[2] Averch H. and L. Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review*, December 1962, pp. 1053–69.

[3] Bailey, E. E., "Peak Load Pricing under Regulatory Constraint," *Journal of Political Economy*, July 1972, pp. 662–79.

[4] Baumol, et. al., "The Role of Cost in the Minimum Pricing of Railroad Services," *Journal of Business*, December 1972, pp. 357–66.

[5] Baumol, W. J. and D. F. Bradford, "Op-

timal Departures from Marginal Cost Pricing," *American Economic Review,* June 1970, pp. 265–83.

[6] Berlin, E., C. Cicchetti, and W. Gillen, *Perspective on Power,* Cambridge, Massachusetts: Ballinger Publishing Company, 1974.

[7] Bonbright, J., *Principles of Public Utility Rates,* New York: Columbia University Press, 1961.

[8] Bower R. S., and R. J. Rohr, "Incremental Cost Pricing of Residential Electric Service," *Public Utilities Fortnightly,* December 5, 1974.

[9] Caywood, R., *Electric Utility Rate Economics,* New York: McGraw-Hill, 1956.

[10] Doran, J., *et al., Cost Allocation Manual,* Washington, D.C., National Association of Regulatory Utility Commissioners, 1973.

[11] Energy Policy Project of the Ford Foundation, *A Time to Choose,* Cambridge, Massachusetts: Ballinger Publishing Company, 1974.

[12] Joskow, P., "Applying Economic Principles to Public Utility Rate Structures: The Case of Electricity," mimeo., July 1973.

[13] Keynes, J. M., *The General Theory of Employment Interest and Money,* New York: Harcourt, Brace and Company, 1936.

[14] Kahn, A. E., *The Economics of Regulation: Principles and Institutions,* Volume I and II, New York: John Wiley and Sons, 1970.

[15] Laaspere, T., "On European Approaches to Managing the Electric Load," Report No. DVE-2, Research Program on Technology and Public Policy, Thayer School of Engineering, Dartmouth College, Hanover, New Hampshire, 1974.

[16] Pressman, I., "Peak Load Pricing," *Bell Journal of Economics and Management Science,* Autumn 1970, pp. 191–210.

[17] Turvey, R., *Economic Analysis and Public Enterprises,* Totowa, New Jersey: Rowman and Littlefield, 1971.

[18] Turvey, R., *Optimal Pricing and Investment in Electricity Supply,* The MIT Press, Cambridge, Massachusetts, 1968.

[19] Williamson, O. E., "Peak Load Pricing and Optimal Capacity under Indivisibility Constraints," *American Economic Review,* September 1966, pp. 810–27.