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RESEARCH TECHNICAL COMPLETION REPORT

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OPTIMAL PRICING AND REGULATION OF ELECTRIC ENERGY IN A SYSTEM DEPENDING ON HYDROELECTRIC CAPACITY

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The author wants to make it completely clear that the analysis and results of this study are his sole responsibility.

ABSTRACT

Regulation Policies on pricing electric power are examined on normative grounds. The implications for pricing electric power in the North Idaho Service Area of the Washington Water Power Company are studied for residential, commercial, and industrial customer classifications. Seasonal and seasonal with time-of-day pricing approaches are evaluated in a benefit-cost framework. Finally, the potential and effects on peak demands, the use of hydroelectric capacity and hence seasonal reservoir fluctuations are examined.

The study finds that time-of-day pricing may not be desirable for residential and commercial customers in Northern Idaho. Industrial customers would clearly benefit. At the same time the results suggest that even with the conservative approach taken to evaluating seasonal reservoir effects, such effects appear to be important.

INTRODUCTION

Electric power loads in Idaho and the Northwest fluctuate with a definite seasonal and time-of-day pattern. The hydroelectric system in the region, coordinated by privately-owned utilities, publicly-owned utilities, and federal authorities, meets much of this fluctuation with an integrated scheduling of reservoir storage and release.[1] Together with flood control and irrigation activities, hydroelectric generation imparts a sequence of stream-flow and reservoir conditions that influence wildlife populations, aquatic populations, recreation activities, and commercial navigation.[2] In addition, flood control measures restrict electrical generation seasonally, and irrigation removes water that would otherwise flow downstream to generate power.[3] The trade-offs and opportunity costs of water use and control in competing alternatives require serious evaluation and are the topic of rapidly expanding controversy. Broadly speaking, these problems are problems of market failure. For example, there would be no need to question water allocation as between hydroelectric generation and irrigation if a market existed allowing water to be sold to those parties and in those amounts with the greatest economic value. Farming interests with water rights would then decide whether more income could be earned by diverting water all for irrigation or whether more income would come from selling part of the water to an electric utility. Thus, the market mechanism, while not forcing allocation, would establish incentives to allocate water in that direction having the most economic value.

The problem of reducing distortions in water use is not only a problem of remedying market failure, but it is also a problem of selecting appropriate policies in pricing electric power. Electricity prices determine seasonal and time-of-day electric demands, a pattern of hydroelectric generation and, hence, contribute to seasonal reservoir and river conditions. Concern with current policies on pricing is the concern that these policies while aimed at establishing equity between the customer of and stockholder in the utility, do so at a serious sacrifice of economic efficiency or, less abstractly, with the promotion of waste in energy use, excessive growth in energy demand and a potential for energy crisis. Specifically current regulatory policy, while seeking prices that yield a fair rate-of-return on investment to the stockholder in the utility and a 'reasonable' price to the customer, in fact establishes prices that are below the cost of new production and that do not correctly reflect the differential costs of supplying different customers or supplying the same customer across time-of-day and seasonal time periods.

It must be understood that the principal function of prices is to convey information on the costs of scarce resources used up in the supply of a product. In this way prices ensure that limited resources will be used in those ways yielding the most benefits to all. At the same time prices function to provide an incentive to develop alternative resources, new technology and appropriate conservation strategies. In both functions the relevant prices are those that measure the current or marginal cost of obtaining more of the product (in this case electrical power)---for it is the allocation of currently available economic resources that raises the fundamental problem. Embedded, accounting, historical or fully allocated costs are all largely irrelevant since these costs concepts refer to costs incurred in the past and those costs are generally quite different from today.

The question is then is it desirable or necessary to sacrifice economic efficiency to achieve the current notion of equity? Do alternative pricing schemes exist that will maintain the same degree of customer-stockholder equity but restore in some measure the economic functions of prices (economic efficiency)? This study has two purposes. One is to evaluate on normative or welfare grounds, and with reference both to equity and economic efficiency, the benefits and costs of alternative regulatory policies in pricing electric power. The other is to analyze the effects of these pricing policies on seasonal electric loads, hydroelectric generation, and, hence, seasonal reservoir fluctuation.

Scope

The study requires analysis of economic data on demand and costs. It also requires data for and a model of a hydroelectric system. Since utilities and federal authorities in the Northwest work towards integrating the scheduling of hydroelectric generation on a regional scale, the appropriate focus should be the entire Columbia-Snake River hydro system. Data for and models of this system are available, but is is beyond the scope and resources of this study to determine correct electricity prices for all utility service areas contributing to the load on this system. Therefore the strategy followed here was to select a utility service area exhibiting a seasonal load or demand pattern similar to the overall area and then carry the pricing results for alternative seasonal loads in the utility service area over by analogy to the region. 'Residual' loads on the hydro system were then derived and an analysis of seasonal reservoir operations was carried out using a model developed, made available and operated by the U.S. Army Corps of Engineers, North Pacific Division. There is no pretention here that the results obtained from analysis of the hydro system are the last word. These results must be interpreted carefully. However, I am convinced that in many respects they are conservative and indicative of seasonal effects that can be expected to follow from the pricing policies studied.

Structure of the Report

The remainder of the report is divided into four sections, followed by conclusions, recommendations, bibliography, and an appendix. The first of the four sections together with Appendix E provides the normative framework and analysis of pricing policies. The second section, entitled Methodological Considerations and Economic Data, explains the choice of geographic region and describes the data that are used in empirically evaluating the flat-rate and two-part schedule pricing policies outlined in the first section. The third section together with the appendix presents the pricing results and the fourth section applies these results to yield implications for the hydro system and seasonal reservoir operations.

NORMATIVE ANALYSIS OF REGULATORY POLICY ON PRICING ELECTRIC POWER

Current Policy

Regulatory policy in pricing electric power is currently founded on what is called the rate base method of regulation. Simply put, the revenue received in the sale of electric power over the course of a year is decreased by operating or running expenses (plus depreciation, taxes and transmission and distribution expenses) incurred in production and the remaining or net revenue is divided by a dollar evaluation of productive plant and facility. The dollar evaluation of plant and facility is referred to as the utility's rate base and the ratio of net revenue to this rate base is viewed by the regulatory commission as the rate of return earned on the rate base or earned by stockholders on their investment in utility plant and equipment. Regulatory practice is then to determine an allowed rate of return or, more realistically, an acceptable range of allowed rates of return. If the utility's earned rate of return is insufficient, a price increase is granted. If it is too high, a rate decrease is ordered.

In itself, this method of regulation generates its own controversial questions: (1) What is a reasonable range for allowed rates of return? (2) How should the rate base, productive plant and equipment, be evaluated? Should plant and equipment be evaluated at original cost, current replacement cost or at some arbitrary intermediate level of cost? (3) How should costs not associated with current production be handled, e.g. should the cost of construction work in progress enter in some measure as part of the rate base or as part of operating expenses? (4) What pricing practice should be followed? The first three questions are distinct from the fourth. The first three are utlimately concerned with establishing a regulatory notion of equity between customer and stockholder while the fourth is concerned with, most importantly, promoting economic efficiency. It should again be emphasized that economic efficiency may be simply thought of as pricing incremental production to reflect its actual resource costs.

As indicated at the outset, the establishment of equity between customer and utility has been the governing objective of regulatory practice. Equity has come to mean that price which allows revenues just sufficient to cover operating or running costs with enough remaining to allow the stockholder a reasonable return on his investment in the utility. Pricing schemes under this approach have resulted in, essentially, an average cost pricing policy.

Average cost pricing in the form it currently takes in Idaho and much of the Northwest is, in fact, inefficient in distributing the burden of costs among customers. For example, costs associated with production are higher in peak-demand periods and lower in off-peak periods, yet present electricity rate schedules do not reflect such differentials.

The Framework for Normative Analysis

Economic efficiency and equity are fundamental objectives in normative analysis. Sometimes referred to as Pareto efficiency or the Pareto criterion of efficiency, economic efficiency represents an outgrowth of the emphasis on individualism in democracy. It predicates on the importance of the individual and the value of free or voluntary exchange among individuals. It is the concept that individuals in a society are better off as a whole if voluntary exchanges or transactions among individuals are promoted and that society is worse-off if involuntary exchanges are required.[4] In economic terms, price represents the economic value placed on a unit of a product.

Marginal cost is the dollar or economic cost of supplying one more unit of the product. If price exceeds marginal cost then the value society places on the product is greater than its cost of production at the margin and with voluntary exchange someone would be willing to supply more of the product up to the point where value or price equals marginal cost. Further production with marginal cost greater than price would entail involuntary or forced transactions since no one would willingly supply the additional product at less than cost-covering prices. Thus the normative principle of economic efficiency is that price should equal marginal cost.

Depending on the pricing scheme adopted, economic efficiency may require a certain sacrifice of equity. Different pricing schemes may alter the trade-off. Whenever a pricing scheme is adopted where a conflict is present, however, a thorny question must be answered: what degree of economic efficiency can be or should be sacrificed to achieve equity or fairness? A sacrifice of economic efficiency clearly promotes waste of the product and potential energy crises; reduced equity means stockholder or certain consumer interests are jeopardized.

Before analyzing alternative pricing policies, on the basis of equity and economic efficiency, it is useful to describe the nature of the particular demand and cost relationships to which these policies will be addressed. The demand for electricity varies across customer classes (residential, commercial, industrial). At any point in time the demand for electric power represents itself as a demand for a flow of electricity or, in more common terminology, a load on the power system. Whether that load is effected by one customer class or whether it is the system load effected by the aggregate of all customer classes, the load typically varies by hour of the day, day of the week and month of the year. Figures 1 and 2 illustrate typical load patterns in North Idaho.[5]

FIGURE 1: Typical Monthly Load Shape Curve

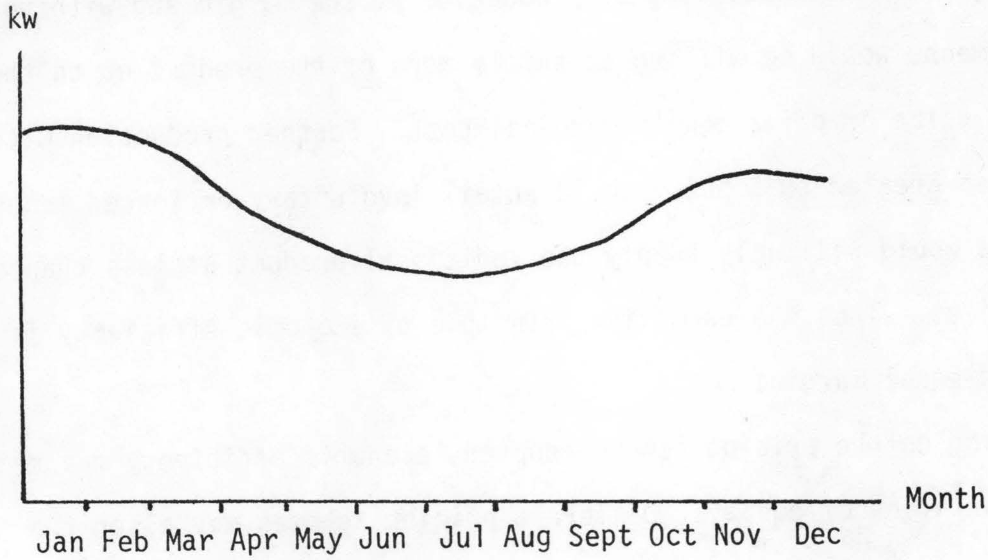
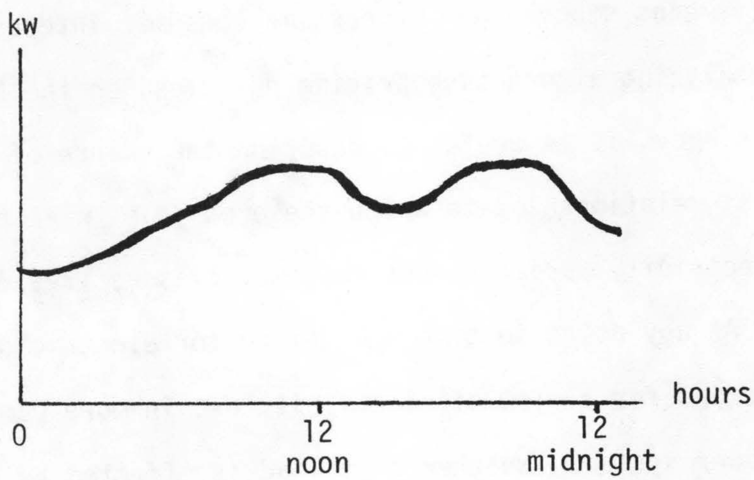


FIGURE 2: Typical Daily Load Shape Curve



The cost of producing electricity in a flow that varies over time to meet the load shape imposed by customers requires the choice of a mix of generating capacity. Generating capacity is of various types and a correct mix of these types is that mix which minimizes the costs of supplying the fluctuating loads imposed.[6] Base load capacity supplies that part of the load pattern which is perpetually present and gas turbine or peaking capacity together with hydroelectric capacity is used in the Northwest to meet larger loads not perpetually present. The costs of supplying the load at any point in time are determined by the types of capacity in use, the necessity to expand capacity, power losses in transmission, the transmission equipment itself, and operating expenses.[7] Consequently, the costs of supplying electricity are differenct depending on the size of the load which itself determines what resources are required.

While a more precise explanation of cost relationships will come later, it is important to recognize here that during periods of peak loads the costs of supply will be greater than during off-peak periods. Therefore an analysis of pricing policy should divide the year into pricing periods on the basis of loads imposed by customers. It is then possible to relate the value placed on electricity use by the customer to the costs of supplying that use.

Flat Rate or Single Tariff Pricing

Flat rate pricing involves pricing electricity in each pricing period with one price - a marginal price. Employing the standard benefit-cost methodology for choosing prices in each pricing period produces the result that economic efficiency is maximized with no consideration of equity. The benefit-cost methodology is explained in the Appendix to this report and is essentially an approach seeking those prices in each of the pricing periods that, together, yield the largest benefit to utility and customer in the sale and purchase of electric power. The implication derived is that prices in each period should be equated to marginal cost. [This result is derived in the appendix as the rule that prices should be chosen so as to satisfy equations (A-3) and (A-8).]

Flat-Rate or Single Tariff Pricing With a Revenue Constraint

A compromise can be achieved between efficiency and the regulatory notion of equity if a constraint is added to the problem. The constraint considered here is that prices in each period be chosen such that the revenue received from (expenditure by) the customer on an annual basis be no more than a specified amount. The result demonstrated in the Appendix is that prices in each of the pricing periods should depart from marginal cost in a specified manner. Generally prices in high-cost, peak demand periods should exhibit a differential over prices during low-cost, off-peak periods, with the overall level of the prices in both periods in fact below marginal costs. [The pricing rule demonstrated in the analytical work in the Appendix is that prices should be chosen to simultaneously satisfy equations (A-3), (A-11), and (A-12).]

Two-Part Pricing Schedule with a Revenue Constraint

Flexibility in achieving both efficiency and through the revenue constraint a regulatory notion of equity is provided by two-part schedule pricing in each pricing period with a revenue constraint across pricing periods fixing the total revenue that the utility may retain per customer. This pricing scheme in essence prices power in each period with a usage price, i.e. a price per kilowatt hour consumed, and a fixed charge or, as demonstrated, a rebate. It should be added that rebate schemes, in this situation, could be undertaken without adding new complexity to the regulation process or administrative activity.

The normative analysis of pricing under this price structure carried out in the Appendix establishes the rule that the usage price should be set at marginal cost, that the fixed charge should - at least for the data analyzed here - be a rebate and that the total of the rebates in all pricing periods should be just sufficient to reduce the average customer's electricity expenditure to the level required by the revenue constraint [equations (A-15), (A-19) and (A-20) must be satisfied in choosing prices and rebates]. The level of rebate in each pricing period is otherwise indeterminant. This approach to pricing thus allows resolution of both the efficiency problem and the equity problem with flexibility as to when and in what manner revenue will be rebated to establish the notion of equity advanced by the regulatory process. Notice that rebate to electricity customers could lead to additional expenditures on electric power. However, rebates should also lead to expenditures elsewhere. To this extent and thus to the extent that the customer effectively views rebates as not reducing electric bills or in fact the marginal usage prices he pays for electricity, an incentive to not waste energy will be established and at the same time the real welfare of the customer would not be diminished. Although ignored here, connection costs and other individual customer costs that do not vary with usage could be netted out against rebates.

Precedent for this type of pricing exists. For example, life insurance policies involve recurring premiums or costs. However, for many types of policies the policyholder once a year receives a dividend payment from the company. The company is basically returning and hence sharing part of its profits with customers. The analysis here based on the Appendix to this report indicates that regulatory policy should consider embracing a similar approach in pricing power.

Conclusions

Pricing strategies subjected to revenue constraints fit well with the current regulatory process in that the current rate base method of regulation could be used to determine the requirement of revenue constraints sufficient for the utility to cover operating costs and provide the stockholder with a reasonable rate of return on investment. In my opinion, the last pricing strategy discussed above is the most desirable. It achieves as normative standards both the regulatory notion of equity and the economic notion of efficiency. It furthermore offers the flexibility that customer classifications could be treated separately. That is, the utility's revenue requirement could be divided among customer classifications so that within each classification prices and rebates would be separately selected.

METHODOLOGICAL CONSIDERATIONS AND ECONOMIC DATA

The North Idaho service area of the Washington Water Power Company was selected as a study area for determining actual prices under the various pricing schemes and then the implications of these prices for altered electric loads. There were two major reasons for employing the North Idaho area. The first was the similarity between the load shape for this area and the load shape for the entire Northwest region (see Figure 3). Southern Idaho and in particular the service area of the Idaho Power Company had been considered but was discarded since irrigation power demands lead to a load shape very different from the Northwest pattern (see Figure 4).

The second reason for selecting the North Idaho region over alternatives was the availability of various types of critical data provided by the excellent staff of the Washington Water Power Company.

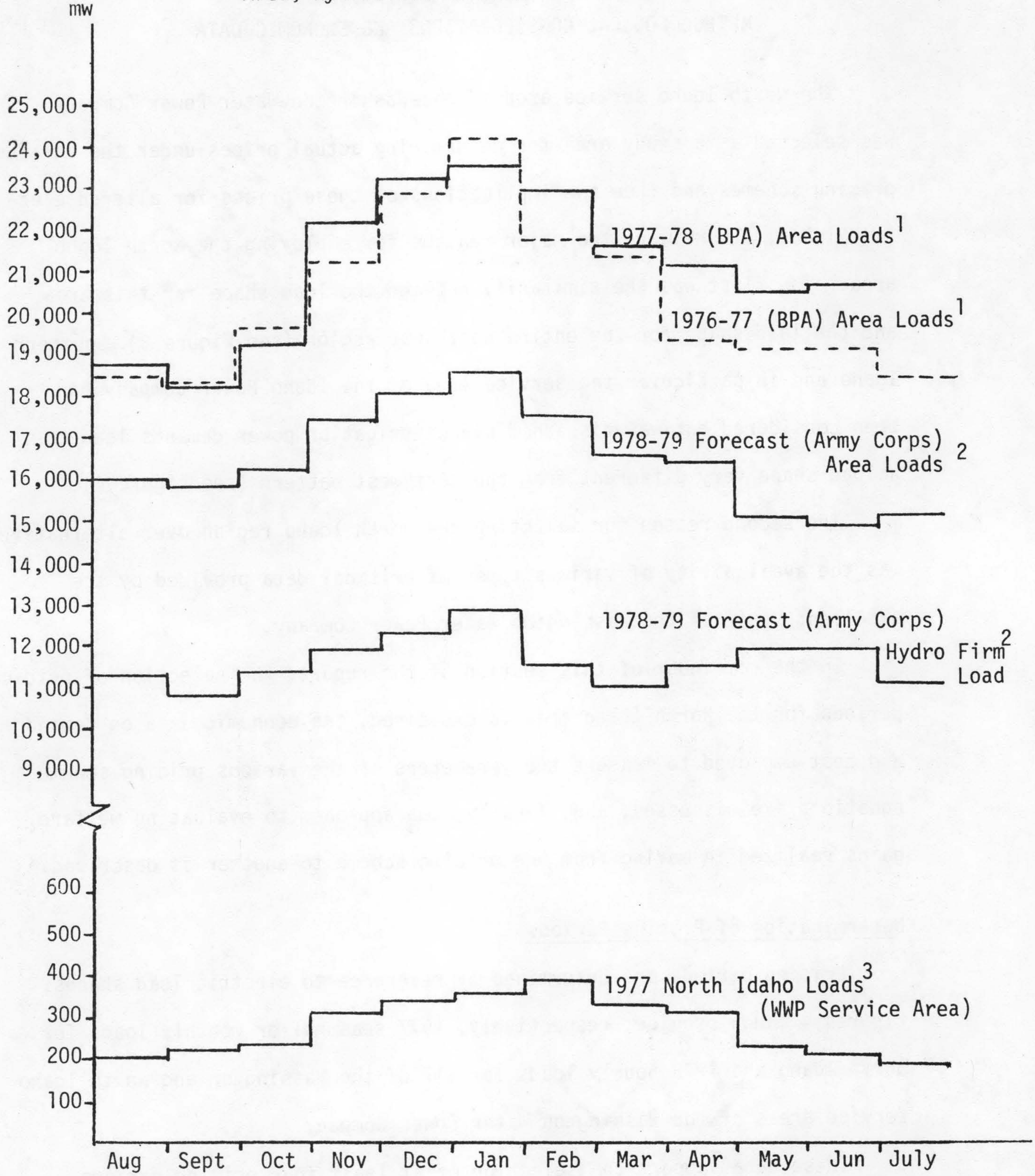
In the remainder of this section of the report, the selection of pricing periods for the North Idaho area is explained, the economic data on demand and cost employed to measure the parameters of the various pricing scheme equations are discussed, and, finally, the approach to evaluating welfare gains realized in moving from one pricing scheme to another is described.

Determination of Pricing Periods

Pricing periods are determined by reference to electric load shapes. Figures 4 and 5 provide, respectively, 1977 seasonal or monthly loads for North Idaho and 1978 hourly loads for all of the Washington and North Idaho service areas of the Washington Water Power Company.

These data support the selection of at least four pricing periods: Winter Days, Winter Nights, Summer Days and Summer Nights. The choice of

FIGURE 3: Monthly Load Comparison: North Idaho, Northwest Area, Hydroelectric Load

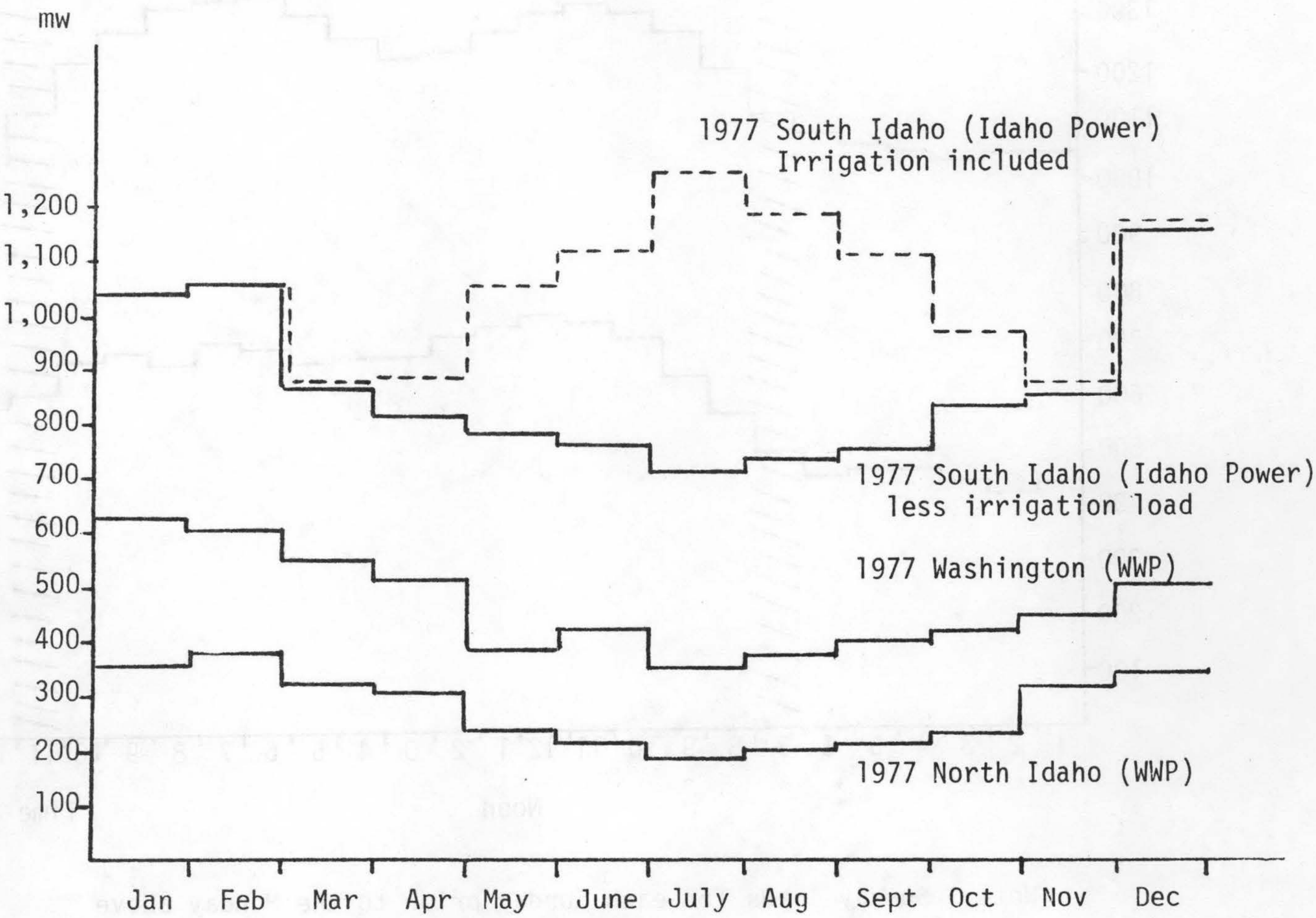


[1]Source: Northwest Power Pool

[2]Source: U.S. Army Corps of Engineers, North Pacific Division

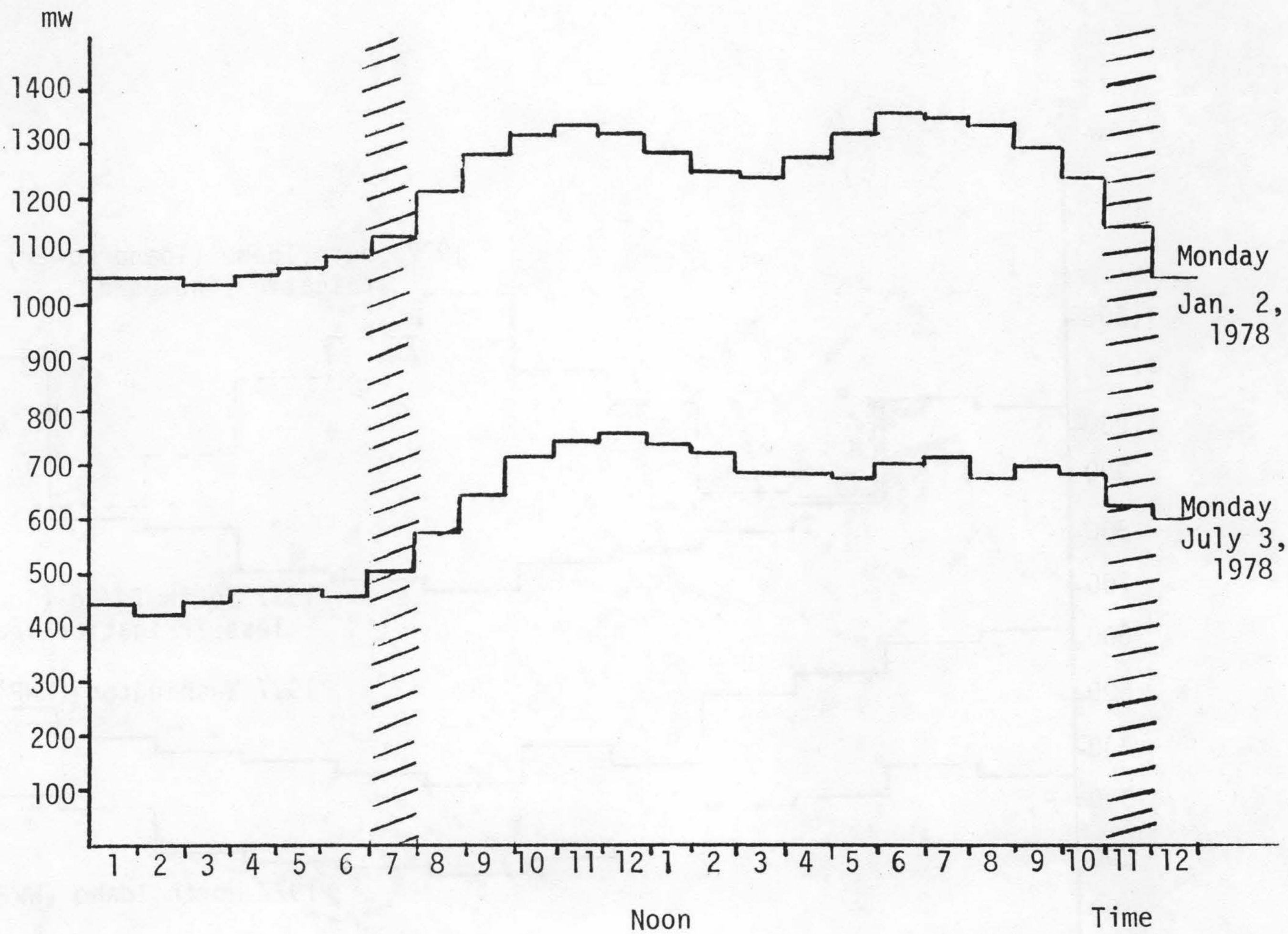
[3]Source: The Washington Water Power Company

FIGURE 4: Monthly Load Comparison: North and South Idaho



Source: The Idaho Power Company and the Washington Water Power Company

FIGURE 5: Washington Water Power System Hourly Loads



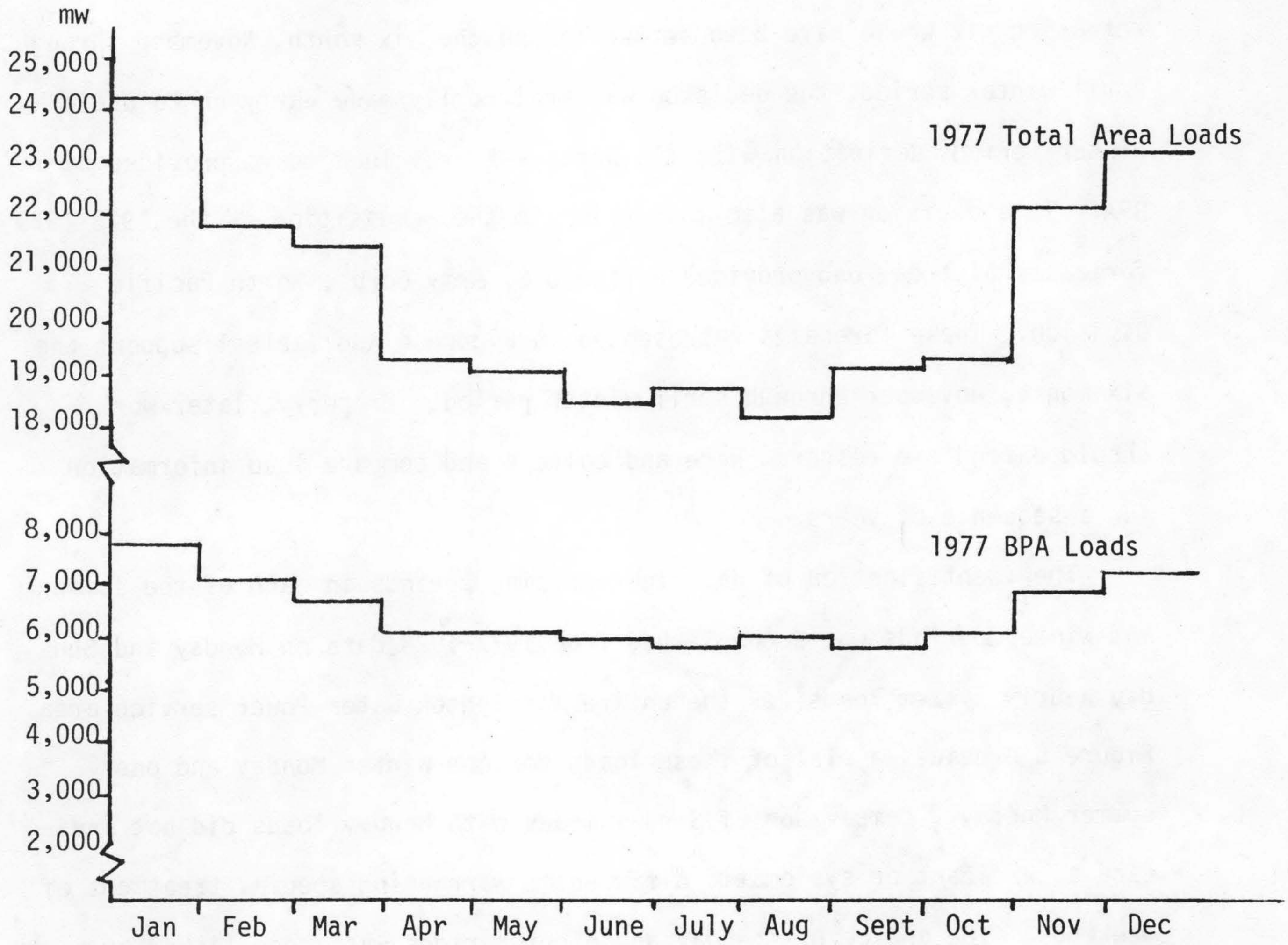
Note: Sunday loads for each Sunday prior to the Monday above are, respectively, very similar to the Monday load pattern. This observation seems to hold true for other Sunday-Monday comparison for which data were available and suggests that weekend-weekday load difference distinctions are not necessary.

Source: The Washington Water Power Company what part of the year to consider winter and what part summer would, from Figure 4, seem to be the months of November through April and May through October, respectively. If one were looking at Northwest Area loads provided by BPA and represented in Figure 6, April would be made part of the summer period leaving only five months in the winter period. While in retrospect it would have been better to use the six month, November through April winter period, the decision was arbitrarily made early-on to use a winter period definition with the Northwest area load curve provided by BPA. This decision was also made prior to the acquisition of the 1978-1979 forecasts of area load provided by the U.S. Army Corps, North Pacific Division. These forecasts represented in Figure 4 and Table 1 support the six-month, November through April winter period. Properly, later work should extend the research here and collect and compare load information for a sequence of years.

The identification of day-night pricing periods in each of the summer and winter periods was accomplished from 1977-1978 data on Monday and Sunday hourly system loads for the entire Washington Water Power service area. Figure 5 provides a plot of these loads for one winter Monday and one summer Monday. Comparison of Sunday loads with Monday loads did not indicate significant or systematic differences warranting special treatment of weekends. The choice of the day and night periods was accomplished by comparing all Monday results. The day period was chosen as that period from 7:00 a.m. through 11:00 p.m. (or to 12:00 midnight), 17 hours, and the night period occupying the remainder, 7 hours.

Ideally, seasonal and time-of-day pricing periods should be chosen with the difference between load and capacity also taken into account. This would

FIGURE 6: Monthly Load Comparison: BPA and Northwest Area



Source: Northwest Power Pool, Summary of Log Sheet Net System Loads

TABLE 1: Monthly Loads

Region	Monthly Loads (1977)*											
	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
NORTH IDAHO[1] (WWP)	363	383	328	317	231	216	197	205	217	237	314	345
WASHINGTON[1] (WWP)	633	604	558	515	393	421	359	366	397	407	441	601
TOTAL[1]	999	987	886	832	624	637	556	571	614	644	755	946
SOUTH IDAHO[2] (IP)												
(1) Less IRR	1041	1060	874	819	787	766	715	727	731	838	844	1158
(2) IRR	1	1	5	75	266	358	550	466	375	132	28	3
(3) TOT	1042	1061	879	894	1053	1124	1265	1193	1106	970	872	1161
BPA[3]	7790	7053	6755	6184	6179	6005	5946	6016	5885	6162	6972	7217
AREA[3]	24246	21749	21485	19326	19051	19019	18567	18726	18244	19258	22211	23221

*monthly loads are in megawatts (mw)

[1]Source: The Washington Water Power Company. Their load data are for Washington Water Power's service areas.

[2]Source: The Idaho Power Company monthly reports. These data are for Idaho Power's service areas in Southern Idaho.

[3]Source: Northwest Power Pool, Summary of Log Sheet Net System Loads.

involve considering what are referred to as cost-of-load-probabilities and will be a topic discussed later in this report (pp 30-31).

Demand Functions

For each customer grouping (residential, commercial and industrial) there are four (k=4) pricing periods and hence four demand functions that must be specified. These demand functions, referred to in the appendix as the first k=4 of the n demand functions represented by equation (A-3) are all specified in the analysis here with a constant elasticity of demand functional form. For each customer grouping this form would be:

$$q_i = b_{oi} \, p_1^{\,b_{1i}} \, p_2^{\,b_{2i}} \cdots p_n^{\,b_{ni}} \, M^{\eta_i} \qquad i = 1,..,k \qquad (1)$$

where b_{oi}, b_{1i}, ..., b_{ni}, η_i (i = 1,.,k) are parameters to be measured and the remainder are variables defined in the Appendix.

Since p_1, ..., p_k are the only prices to be varied under different pricing schemes, (1) may be simplied to:

$$q_i = b'_{oi} \, p^{\,b_{1i}} \cdots p_k^{\,b_{ki}} \qquad (2)$$

This form for the demand function is a commonly used form and it is my feeling that it represents a sufficiently close approximation to actual behavior so that the results of the analysis here would not be significantly altered were closer approximations available.

Demand Elasticities

The parameters of this specification are, in part, interpretable as demand elasticities. For i≠j and j≠0, b_{ni} is the cross-price elasticity of demand for consumption in the i^{th} pricing period with respect to the price in the j^{th} pricing period. Simply put, a cross-price elasticity allows for the possibility that the level of price in one pricing period may influence customer electricity consumption in other pricing periods. For example, customers may be able to put off electricity consumption from day to night, and commercial and industrial customers, specifically, may be able to adjust production activities on a seasonal scale and hence seasonally alter electricity consumption levels. No evidence is yet available that would provide reasonable estimates of cross-price effects. Therefore, results may be obtained only with hypothetical values. The work in this study in evaluating alternative pricing schemes was carried out completely for $j \neq i$ and $i \neq 0$ first assuming $b_{ji}=0$ and then allowing $b_{ji}=-.1$ and finally setting $b_{ji}=+.1$.

For i=j, b_{ji} is the own price elasticity of demand. It was originally the decision to carry out an econometric study of price elasticities of demand in the North Idaho region. That study is not yet complete due to data problems. However, as an alternative to such an empirical analysis of the most recent data for the North Idaho area, there is a certain amount of evidence for the Northwest in general that, if examined carefully, will in my judgment suggest reasonable measures of price elasticity.[8] In fact, for purposes of carrying out computations that will be used as a basis for plausible alternatives in the shape of Northwest area loads and then hydro system loads, the use of price elasticity estimates for the area is desirable.

Price elasticities estimated specifically for the Northwest are summarized in Table 2. In order to use these estimates in the problem at hand some interpretation is necessary and it must be clearly understood

TABLE 2: Price Elasticity Estimates

Study (Data Period)	Elasticity	Price employed
Residential Customer Classification		
Lyman (1959-1968)	-1.15	Average Price
BPA (1966)	- .70	Price for 1000 kwh
	- .76	Average price
PBA (1972)	- .59	Price for 1000 kwh
	- .67	Average price
PNUCC (1975-1976)	- .86	Marginal price and typical electric bill for 1000 kwh
Commercial Customer Classification		
Lyman (1961-1968)	- .92	Average price
BPA (1972)	-1.07 to -1.14	Average price
	- .43	Price of 6000 kwh
PNUCC (1975-1976)	- .81	Marginal price
Industrial Customer Classification		
Lyman (1961-1968)	-1.59	Average price
BPA (1972)	-1.56	Average price
PNUCC (1975-1976)	- .41 to -2.14	Average price

*I computed this elasticity using 1976 base values for variables. Any errors in the computations are my responsibility.

that across the four pricing periods for each customer grouping, the price elasticity will be assumed to be the same.

Now, focussing on interpretation, the decrease in estimated residential elasticity obtained in the BPA study from 1966 to 1972 is consistent with results I obtained with data for the 1959-1968 period. Although the estimated residential elasticity in my work for this period was -1.15.

This was an elasticity computed as an average elasticity for the entire period. Though not indicated in the table, my results show that price elasticity over the period declined with increases in household income. Consequently the 1972 BPA estimates of -.59 and -.67 may be reasonable in comparison with the larger estimate in my study. The residential elasticity estimate obtained in the PNUCC study is subject to suspicion for four reasons: (1) the model of household behavior employed in this study is not justified by economic theory or any systematic theory of rational household behavior that I am aware of; (2) the model specifies that electricity consumption (or usage) per appliance in each appliance category is constant (unaffected by price or other variable) and this is an unreasonable assumption; (3) the model was estimated with data for the rest of the United States and therefore may not be descriptive of conditions in the Northwest; and (4) the model was estimated with state data and there is a significant question of aggregation bias present for those studies using data aggregated to this level.[9]

The results for commercial and industrial demand do not allow the same rich examination. Less is known and there is more uncertainty regarding these results. The problem is clearly that there is more heterogeneity among customers within these classes and the price elasticity estimates derived with data that do not adequately reflect or near that heterogeneity may be biased.

A conservative assumption in view of the possible problems is that for the average customer, the commercial and industrial price elasticities at least lie in the range from -.6 to -.8 with the residential elasticity at least -.6. These elasticities must be viewed as long-run elasticities.

That is they indicate the degree to which demand will respond to price with enough time allowed for customers to complete all or most adjustments. In the short-run, price elasticities would be expected to be less.[10] Consequently, the analysis of pricing effects will be carried out with both short-run as well as long-run elasticities. The objective is to bracket price responses, at least on the lower end. The elasticities used in this study are presented in Table 3.

TABLE 3: Elasticity Estimates Used in Study

	Short Run 1-2 year response time	Long Run 3-10 year response time
Residential	-.2	-.6 & -.8
Commercial	-.2	-.6 & -.8
Industrial	-.2	-.6 & -.8

Electricity Consumption in Pricing Periods

To complete the quantitative specification of demand functions for each customer grouping, b_{oi}, for i=1,.,4 must be measured. This was accomplished by setting:

$$b_{oi} = \frac{q_i}{p_1^{b_{1i}} \cdots p_k^{b_{ki}}} \qquad i = 1, \ldots, 4 \qquad (3)$$

The values to be used for the parameters b_{1i} through b_{ki} were discussed above. The relevant data for q_i for $i=1,..,4$ and for $p_1,..,p_4$ are the actual or original quantities of electricity consumed and the original electricity prices (picked from the rate schedules) at which this consumption occurred in each pricing period. Tables 9, 10, and 11, occurring later in this report provide the data on electricity prices.

The total of electricity consumption in each of the four pricing periods was measured on the basis of 1977 monthly data for average customer consumption, for each customer classification and on the basis of implications drawn from the 1977-1978 system hourly loads for Mondays. Arbitrarily, the load shape found in the hourly loads was, for want of better information, imputed as the representative load shape for each customer classification: residential, commercial and industrial.[11] Thus the hourly system loads were used to determine the percentages of electricity consumption falling in the day-night periods. The result was that average customer kilowatt-hour consumption occurring for each customer class in the winter and summer periods was divided in each period into a day and night component. These numbers are provided below in Table 4:

TABLE 4: Average Customer Electricity Consumption (kwh)[1]

	Pricing Period			
Customer	SD	SN	WD	WN
Residential	5,185	1,728	6,799	1,918
Commercial	18,122	6,041	17,515	4,940
Industrial	919,406	306,468	1,184,983	334,226

[1]To illustrate the interpretation of the Table the 5185 kwh consumed by the residential electric customer in the SD period represents the total of all electric consumption over all summer days by the average residential customer.

It must be understood that while this analysis assumes the existence of an average customer, such customers do not always exist. This is certainly the case in the residential classification. It was fortunate that

TABLE 5: Residential Customer Load Variation: 24 Hour Period of the Day[1]

Date	Customer Type[2] Electric Heat	Diversified Heat	Alternative Heat
WINTER			
Dec. 1 - Residential Peak Demand in Month			
Day:	4.9-13.5	4.6-9.1	1.3-2.7
Night:	4.4- 8.1	4.6-6.1	.7-1.4
Dec. 6 - System Peak Demand in Month			
Day:	5.0-10.0	5.4-7.9	1.2-2.7
Night:	4.0- 7.6	4.3-5.5	.7-1.4
SUMMER			
July 7 - Residential Peak Demand in Month			
Day:	1.3- 4.5	.9-2.4	.9-2.4
Night:	.7- 2.7	.5-1.7	.4- .8
July 22 - System Peak Demand in Month			
Day:	1.7- 3.4	1.0-2.5	1.2-2.5
Night:	.6- 2.5	.5-1.5	.4-1.4

[1]Source: The Washington Water Power Company. Washington Water Power monitored electric loads at 15 minute intervals to various types of residential customers in a total sample of 18 households. The load variation data here were constructed by me from the Washington Water Power data on actual loads and represent my approximations of load ranges. Any inaccuracies that may be present in this table are my responsibility and purely unintentional.

[2]Customer types are defined as follows:
(1) Electric Heat - the home employs an electric furnace.
(2) Diversified Heat - heating involves electric baseboard heat and similar alternatives using electricity.
(3) Alternative Heat - the home is heated by other than electric sources.

Washington Water Power was able to provide data on different types of residential customers, allowing comparisions. Table 5 describes how the electric consumption pattern for different types of residential customers varies in terms of the load these customers individually impose on the system. Kilowatt-hour consumption levels were derived for the four pricing periods for the different types of residential customers and they are reported in Table 6:

TABLE 6: Residential Customer Electricity Consumption (kwh) by Pricing Period

Customer Type	Pricing Period			
	SD	SN	WD	WN
Average	5185	1728	6799	1918
Electric Heat	9587	2910	21562	6342
Diversified Heat	5820	1712	17456	5891
Alternative Heat	5820	1369	5134	1057

For final descriptive comparison, Table 7 provides average loads by month for average customers across the three customer classes.

Determination of Marginal Costs

From the equations describing pricing schemes in the Appendix, it will be clear that the relevant cost information needed is information on incremental or marginal costs of supply. Data on marginal costs are not widely available with the exception of recent individual efforts by Washington Water Power and the Bonneville Power Administration, and the various

TABLE 7: Average Hourly Customer Load Measured in kw[1] (1977)

Month	Customer Residential	Commercial	Industrial
January	2.80	6.48	435.48
February	2.76	7.07	491.16
March	2.23	6.02	419.49
April	1.98	5.48	439.28
May	1.40	4.58	225.26
June	1.33	4.56	191.97
July	1.09	4.34	170.37
August	1.07	4.57	182.65
September	1.17	4.84	191.20
October	1.39	4.59	273.47
November	1.84	5.31	347.47
December	2.42	6.15	407.08

[1] Computed from monthly data supplied by The Washington Water Power Company on kwh consumption totals and number of customers in each of the residential, commercial and industrial customer categories.

proceedings during 1977-1978 before the Public Utility Commissioner of Oregon.

It should be understood that marginal cost is the important and relevant cost concept as it measures the cost of supplying a customer with additional electricity. The marginal cost of supply depends on (1) the size of the electric load and hence the possibility that generating and transmission capacity will have to be expanded to meet an increased demand or load, and (2) the voltage at which the customer receives the power from

The importance of voltage is adequately explained elsewhere.[12] It is worthwhile however, to comment on the relationship between marginal cost and the size of the electric load.

There are two possibilities for meeting an increased load during a peak period. One is to use thermal peaking plants such as gas turbine thermal plants which generate their own energy. The other is to build a pumped storage facility or add to the existing generating capacity of a reservoir. Either of these last hydro possibilities does not increase or result in the generation of energy in the system.[13] Rather, these approaches serve to shift energy previously supplied at other times of the year around to the peak period. This approach to meeting an increased peak demand must be accompanied by the construction of some type of thermal generating facility that will serve to increase the energy available. The total cost therefore of meeting an increased load at the peak with pumped storage or modifications to the hydro system must include the capacity and operating costs of the thermal facility built to supply the increased energy requirements of the larger peak load.

The decision in this study was to compute marginal cost at the peak assuming that increased demands in this period would be supplied with gas turbine capacity. There are two reasons for this decision. The first is that when computed properly the alternative hydro developments discussed above together with the required thermal plant additions may yield very similar costs. The second is that pumped storage facilities and reservoirs modified with additional generating capacity will very likely result in unacceptable river level fluctuations. These types of developments therefore may have only a limited potential in supplying peak demand growth.

Increased loads during the off-peak period require no increment to capacity since sufficient capacity already exists. The cost of off-peak growth in demand or load is therefore largely a running or operating cost. Expenses during the peak load periods, however, would include both the operating or running costs and a capacity cost. Capacity has to be expanded as peak demand grows.

The estimates of marginal costs in peak and off-peak periods that are employed here were obtained from Washington Water Power and are summarized in Table 8:

TABLE 8: WWP Marginal Costs (1978 dollars)[1]

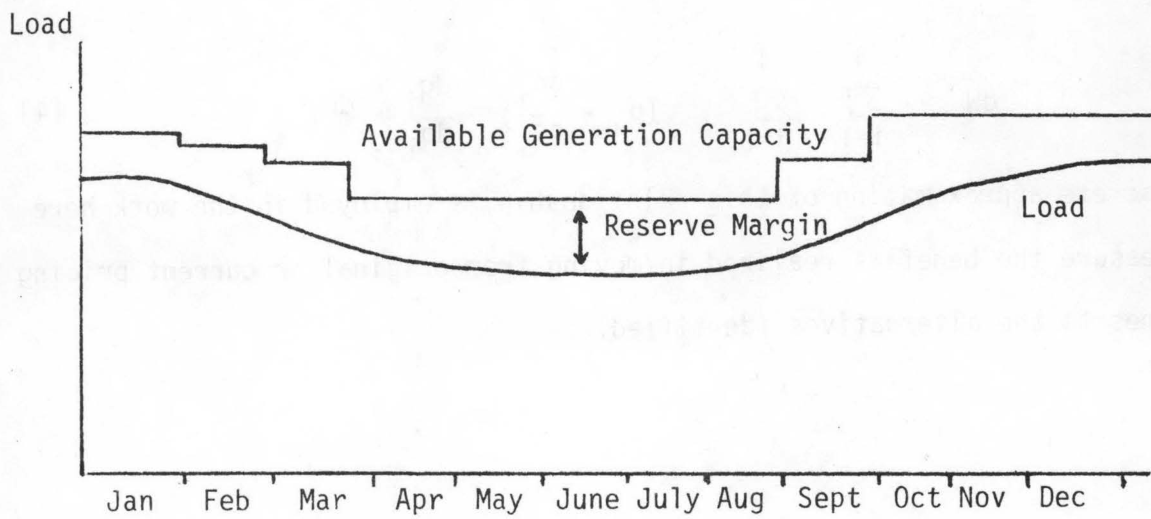
	Period	
Type of Cost	Peak (¢/kwh)	Off-Peak (¢/kwh)
Capacity	1.4¢	0
Energy	2.47¢	2.47¢
Energy Adjusted for Losses	2.71¢	2.71¢
Total	4.11¢	2.71¢

[1]Source: Washington Water Power Company

Complete reliance on these costs is complicated by the possibility that a pricing strategy may narrow the difference between peak and off-peak demands sufficiently that off-peak demands press against available generating capacity. To appreciate this point it is necessary to recognize that not all generating capacity is continuously available. Rather, a program of planned outage must be carried out to complete necessary maintenance. Planned outages are systematically scheduled for off-peak load periods. The typical result, displayed in Figure 7, is that an increase in off-peak loads could in fact invade reserve margins, that is, the margin by which available capacity exceeds expected load. The probability that this will occur is referred to as loss of load probability (LOLP) and LOLP's can and are used to assign costs. LOLP's were not used in this research to assign marginal costs but the results provided later suggest that this approach should be considered in subsequent work.[14]

It should be noted that the principal problem we're using LOLP's is that they themselves are dependent on such things as load shape and to my knowledge no one has adequately incorporated this factor in analysis.

FIGURE 7: Capacity, Load, Reserve Margin



A final note is that there are differential costs in supplying customers in different classes. For example, the cost of supplying power varies inversely with the voltage at which the customer receives the power. As a first approximation, these costs were ignored here. Later research should, however, determine and incorporate these costs in establishing marginal costs by customer classification.

Benefits Accruing from Alternative Pricing Schemes

The benefits in scrapping a current pricing scheme in favor of an alternative are the welfare losses that can be eliminated or welfare gains achieved through the alternative prices. Referring to the Appendix, differential effects on welfare for a customer are described by equations (A-4) and (A-5) and by Figure A-1. Differential effects on the welfare of the utility or its stockholders are measured through differential effects on total profits to the firm. The net of differential effects in adopting one pricing scheme or another may be represented in the notation of the Appendix as:

$$dW = \sum_{i=1}^{4} \sum_{j=1}^{4} \left(p_i - \frac{dc_i}{dq_i}\right) \frac{dq_i}{dp_i} \, dp_i \qquad (4)$$

A discrete approximation of this relationship is employed in the work here to measure the benefits realized in moving from original or current pricing schemes to the alternatives identified.

ANALYSIS OF DIFFERENT PRICING SCHEMES IN WASHINGTON WATER POWER'S NORTH IDAHO SERVICE AREA

The three pricing schemes evaluated are defined in the Appendix. The economic data discussed in the previous section of this study provide quantitative measurement of the parameters of the equations defining each pricing scheme. The revenue constraint, for the two schemes that employ such a constraint, specifies that in each customer classification the expenditure of an average customer in that classification not exceed the 1977 level (computed under 1977 prices). Different revenue constraints were therefore individually applied to different customer classifications.

For simplicity, the findings that will be reported in this section are those only for the case where cross-price elasticities are zero. Suffice it to mention that the presence of non zero cross-price effects, mentioned in the previous section, increases the benefits from adopting the pricing schemes analyzed.

Seasonal Versus Time-of-Day Pricing

The pricing periods in this study involve both time-of-day or day-night periods and seasonal periods. Pricing between day-night periods is, in common terminology, time-of-day pricing and requires the expense of additional metering for each customer. Since seasonal pricing does not require such expense, it is important to evaluate the differential benefits of seasonal and time-of-day pricing (STD pricing) over only seasonal pricing (S pricing). To allow this evaluation each pricing scheme analyzed in the results that follow is examined first assuming STD pricing and then assuming S pricing. The benefits in each case are computed as a dollar total.

Findings

It is important to keep in mind that the pricing schemes analyzed here (flat rate pricing, flat rate pricing subject to a revenue constraint, and two-part schedule pricing subject to a revenue constraint) are evaluated in the framework of exchange involving for each customer classification the utility and the average customer. Thus tables 9, 10, and 11 include, for each of the residential, commercial and industrial customer classifications, the original prices and consumption levels for an average customer and the new or optimal prices under the different pricing schemes together with the emerging consumption pattern over pricing periods. The computations are carried out assuming a reasonable approximation for short-run price elasticity (-.2) and then an approximation for a longer-term price response (-.6).

It will be apparent from these first three tables that the flat-rate pricing scheme and the two-part schedule scheme subject to a revenue constraint are both associated with the same prices and emerging consumption pattern across pricing periods. This finding is only roughly correct. In actuality both pricing schemes do result in the same marginal prices for electricity in each pricing period. However, the two-part scheme with a revenue constraint requires a rebate to the customer and that rebate on an annual basis can be expected to encourage a larger consumption in each period. Dividend receipts to holders of life insurance policies are not spent entirely on additional life insurance and certainly the same would be true with rebates to electricity customers. In fact there is reason to believe that, although larger, pricing period consumption under two-part schedule pricing should not be significantly larger.

TABLE 9: Residential Prices and Quantities: Average Customer

Pricing Method	Economic Variable	Pricing Periods			
		Summer Days	Summer Nights	Winter Days	Winter Nights
(1) Original Values					
Original Customer Charge (assessed monthly at $2.60)					
	Price (¢)	1.07¢	1.07¢	1.07¢	1.07¢
	Quantity (kwh)	5185	1728	6799	1918
(2) Flat Rate Pricing and Two-Part Schedule Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Seasonal	Price	2.71¢	2.71¢	3.79¢	3.79¢
	Quantity	4309	1436	5279	1489
STD	Price	2.71¢	2.71¢	4.10¢	2.71¢
	Quantity	4309	1436	5197	1594
Price elasticity = -.6					
Seasonal	Price	2.71¢	2.71¢	3.79¢	3.79¢
	Quantity	2976	992	3182	898
STD	Price	2.71¢	2.71¢	4.10¢	2.71¢
	Quantity	2976	992	3037	1101
(3) Flat Rate Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Seasonal	Price	1.08¢	1.08¢	1.52¢	1.52¢
	Quantity	5171	1723	6336	1787
STD	Price	1.09¢	1.09¢	1.65¢	1.09¢
	Quantity	5170	1723	6236	1912
Price elasticity = -.6					
Seasonal	Price	1.35¢	1.35¢	1.90¢	1.90¢
	Quantity	4510	1503	4823	1361
STD	Price	1.36¢	1.36¢	2.06¢	1.36¢
	Quantity	4497	1499	4589	1663

TABLE 10: Commercial Prices and Quantities: Average Customer

Pricing Method	Economic Variable	Pricing Periods			
		Summer Days	Summer Nights	Winter Days	Winter Nights
(1) Original Values					
Customer and Demand Charges are Assessed Monthly.[1]					
	Price (¢)	1.48¢	1.48¢	1.48¢	1.48¢
	Quantity (kwh)	18122	6041	17515	4940
(2) Flat Rate Pricing and Two-part Schedule Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Seasonal	Price	2.71¢	2.71¢	3.79¢	3.79¢
	Quantity	16069	5357	14511	4093
STD	Price	2.71¢	2.71¢	4.10¢	2.71¢
	Quantity	16069	5357	14286	4380
Price elasticity = -.6					
Seasonal	Price	2.71¢	2.71¢	3.79¢	3.79¢
	Quantity	12634	4212	9960	2809
STD	Price	2.71¢	2.71¢	4.10¢	2.71¢
	Quantity	12634	4212	9504	3444
(3) Flat Rate Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Seasonal	Price	1.59¢	1.59¢	2.24¢	2.24¢
	Quantity	17861	5954	16129	4549
STD	Price	1.59¢	1.59¢	2.42¢	1.59¢
	Quantity	17856	5952	15875	4867
Price elasticity = -.6					
Seasonal	Price	2.05¢	2.05¢	2.88¢	2.88¢
	Quantity	14902	4968	11748	3313
STD	Price	2.06¢	2.06¢	3.13¢	2.06¢
	Quantity	14866	4955	11182	4052

[1]Customer charge is $2.60 and demand charge is $1.75/kwh for all kw > 20 kw. Prices in the table are marginal prices picked off 1977 rate schedules in the consumption block nearest to the consumption of the average customer.

TABLE 11: Industrial Prices and Quantities: Average Customer

Pricing Method	Economic Variable	Pricing Period: Summer Days	Summer Nights	Winter Days	Winter Nights
(1) Original Values					
A Demand Charge is Assessed Monthly.[1]					
	Price (¢)	.69¢	.69¢	.69¢	.69¢
	Quantity (kwh)	919406	306468	1184983	334226
(2) Flat Rate Pricing and Two-part Schedule Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Seasonal	Price	2.71¢	2.71¢	3.79¢	2.71¢
	Quantity	699849	233283	842768	237704
STD	Price	2.71¢	2.71¢	4.10¢	2.71¢
	Quantity	699849	233283	829708	254412
Price elasticity = -.6					
Seasonal	Price	2.71¢	2.71¢	3.79¢	2.71¢
	Quantity	405507	135169	426285	120234
STD	Price	2.71¢	2.71¢	4.10¢	2.71¢
	Quantity	405507	135169	406772	147412
(3) Flat Rate Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Seasonal	Price	.89¢	.89¢	1.25¢	1.25¢
	Quantity	874323	291440	1052872	296964
STD	Price	.89¢	.89¢	1.35¢	.89¢
	Quantity	874044	291347	1036225	317736
Price elasticity = -.6					
Seasonal	Price	1.40¢	1.40¢	1.97¢	1.87¢
	Quantity	601343	200447	632157	178301
STD	Price	1.41¢	1.41¢	2.14¢	1.41¢
	Quantity	599652	199884	601523	217988

[1] The demand charge is $87.50 for the first 50 kw of demand and $1.00/kw for all additional kw. Prices in the table are marginal prices picked off 1977 rate schedules in the consumption block nearest to the consumption of the average customer.

Table 12 explores expected consumption responses to the prices displayed in Table 9 for residential customers of different types. In this table the electric heat customer is that customer who heats his home with an electric space heating furnace; the diversified heat customer is a household employing baseboard heat; and the alternative heat customer is the household that relies on natural gas or an alternative source of home heating--alternative to electricity.

Table 13 provides average monthly bills for the summer (S) and winter (W) periods of the year. Also, item 4 in Table 13 provides a computation of the annual total of rebates that would occur under the two-part schedule pricing scheme. Clearly these rebates are contingent on (1) the assumed price elasticity and (2) the requirement that the annual total of expenditures for the average customer in a classification not exceed the 1977 total under the original, 1977 prices. Since the summer (S) and Winter (W) periods include, respectively, 7 and 5 months, total annual expenditures can be computed by multiplying average monthly bills by the appropriate number of months and totalling for the two periods.

Finally, Table 14 reports the increment or increased benefits to utility and customer in the case of each pricing scheme of first moving to a seasonal version of the scheme and then from the seasonal version to the STD version of the scheme. In all cases these are benefits per customer.

Quite clearly the adoption of flat rate (single marginal price) pricing or two-part schedule pricing under a revenue constraint would produce the largest increase in benefits with the only difference, that the latter scheme ensures an 'equitable' sharing of these benefits between customer and utility stockholders.

TABLE 12: Residential Results: Comparisons Among Types of Customers[1]

Customer Type	Pricing Method	Electricity Consumption in Pricing Periods: Summer Days	Summer Nights	Winter Days	Winter Nights
(1) Original Values					
Electric Heat	original	9587	2910	21563	6342
Diversified Heat	original	5821	1712	17456	5391
Alternative Heat	original	5821	1370	5134	1057
(2) Flat Rate Pricing and Two-part Schedule Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Electric Heat	S	7967	2419	16742	4924
	STD	7967	2419	16483	5270
Diversified Heat	S	4837	1423	13553	4186
	STD	4837	1423	13343	4480
Alternative Heat	S	4837	1138	3986	821
	STD	4837	1138	3924	878
Price elasticity = -.6					
Electric Heat	S	5502	1670	10093	2969
	STD	5502	1670	9031	3639
Diversified Heat	S	3340	982	8170	2523
	STD	3340	982	7796	3094
Alternative Heat	S	3340	786	2403	495
	STD	3340	786	2293	607
(3) Flat Rate Pricing Subject to a Revenue Constraint					
Price elasticity = -.2					
Electric Heat	S	9562	2903	20094	5910
	STD	9559	2902	19776	6323
Diversified Heat	S	5805	1707	16266	5023
	STD	5804	1707	16009	5375
Alternative Heat	S	5805	1366	4784	985
	STD	5804	1366	4709	1054
Price elasticity = -.6					
Electric Heat	S	8339	2531	15297	4499
	STD	8315	2524	14555	5500
Diversified Heat	S	5063	1489	12383	3824
	STD	5048	1485	11783	4675
Alternative Heat	S	5063	1191	3642	750
	STD	5648	1188	3466	917

[1] S and STD stand for seasonal and then seasonal and time-of-day pricing, respectively. Numbers are in kilowatt hours (kwh).

TABLE 13: Average Monthly Electric Bills[1]

Pricing Method	Seasonal Period	Customer Type: Residential Average	Residential Electric Heat	Residential Diversified Heat	Residential Alternative Heat	Commercial Average	Industrial Average
(1) Original Prices (1977)							
Original	S	13.17	21.70	14.11	13.59	63.69	1893.46
	W	21.25	62.32	51.49	15.85	79.07	2781.61
(2) Flat Rate Pricing and Two-part Schedule Pricing Subject to Revenue Constraint							
Price elasticity = -.2							
Seasonal	S	22.16	40.06	24.14	23.05	82.64	3599.22
	W	51.33	164.31	134.53	36.46	141.09	8194.30
STD	S	22.16	40.06	24.14	23.05	82.64	3599.22
	W	51.22	163.62	133.60	36.92	140.80	8177.43
Price elasticity = -.6							
Seasonal	S	15.30	27.66	16.67	15.92	64.98	2085.46
	W	30.94	99.06	81.10	21.98	96.84	4144.81
STD	S	15.30	27.66	16.67	15.92	64.98	2085.46
	W	30.84	98.63	80.64	22.08	96.53	4131.55
(3) Flat Rate Pricing Subject to Revenue Constraint							
Price elasticity = -.2							
Seasonal	S	10.68	19.31	11.64	11.11	54.14	1477.54
	W	24.74	79.19	64.83	17.57	92.43	3363.90
STD	S	10.69	19.33	11.65	11.12	54.20	1479.43
	W	24.72	78.95	64.47	17.82	92.35	3361.26
Price elasticity = -.6							
Seasonal	S	11.60	20.97	12.64	12.06	58.20	1603.69
	W	23.45	75.07	61.47	16.66	86.74	3187.29
STD	S	11.62	21.01	12.66	12.09	58.30	1606.70
	W	23.42	74.89	61.23	16.76	86.61	3183.07
(4) Annual Rebate Under Two-part Schedule Pricing: One Approach							
Price elasticity = -.2							
Seasonal	Annual	213.33	213.33	213.33	213.33	442.75	39,003.77
STD	Annual	212.78	212.78	212.78	212.78	441.30	38,919.42
Price elasticity = -.6							
Seasonal	Annual	63.36	63.36	63.36	63.36	97.88	8160.00
STD	Annual	62.86	62.86	62.86	62.86	96.33	8092.70

[1] Figures in the table are in dollars. S and W refer to Summer and Winter, respectively. STD is an abbreviation for seasonal and time-of-day pricing.

TABLE 14: Annual Incremental Benefits from Adopting Alternative Pricing Schemes[1]

Adjustments in Pricing Scheme	Customer Type					
	Residential				Commercial Average	Industrial Average
	Average	Electric Heat	Diversified Heat	Alternative Heat		
(1) Flat Rate Pricing and Two-part Schedule Pricing Subject to a Revenue Constraint						
Price elasticity = -.2						
original to seasonal	44.31	125.54	97.76	36.14	71.47	12840.16
seasonal to STD	.66	2.17	1.82	.39	1.82	105.47
Price elasticity = -.6						
original to seasonal	113.48	320.21	249.04	92.71	191.25	30812.91
seasonal to STD	1.24	4.06	3.42	.73	3.87	165.66
Price elasticity = -.8						
original to seasonal	140.46	395.63	307.51	114.84	241.46	37215.16
seasonal to STD	1.30	4.28	3.61	.77	4.35	159.90
(2) Flat Rate Pricing Subject to a Revenue Constraint						
Price elasticity = -.2						
original to seasonal	15.21	48.09	39.07	11.19	38.98	5990.33
seasonal to STD	.79	2.23	1.55	.97	2.02	131.74
Price elasticity = -.6						
original to seasonal	73.56	215.87	170.66	57.94	169.49	25994.32
seasonal to STD	1.87	5.18	3.66	2.16	4.56	245.32
Price elasticity = -.8						
original to seasonal	134.37	379.99	295.95	109.36	241.46	37215.16
seasonal to STD	1.60	4.83	3.78	1.38	4.35	159.90

[1] Figures in the table are in dollars. STD refers to seasonal and time-of-day pricing.

SIMULATED IMPACTS ON HYDROELECTRIC GENERATION AND SEASONAL RESERVOIR OPERATION

Alternative monthly load patterns were computed for the North Idaho area under the various pricing schemes analyzed and for the seaonal (S) and the seasonal and time-of-day (STD) pricing approaches. These load patterns were related to the original load pattern in North Idaho by computing for each load pattern an index of load ratios (new/original). Northwest area loads were then altered using these indices. To be conservative and limit implications to just those associated with load shape, the altered Northwest area loads were appropriately adjusted so that the total energy in each altered case was the same as under the original, unaltered load curve. The original, unaltered area loads are those plotted in Figure 3 and referred to as the Army Corps load forecasts.

'Residual' loads to be supplied by the hydro system were then obtained for each overall load pattern by adjusting the various monthly loads in the overall pattern by the contribution of utilities and other area sources to these loads. The contribution or adjustment was obtained from the U.S. Army Corps forecasts as the difference in each month between the original, unaltered forecast of area load and the original forecast of hydro firm load.

In analyzing the operation of the Columbia-Snake River hydro system under different load shapes, it is necessary to assume a set of water conditions. That is, it is necessary to make assumptions as to water run-off in the system over the course of the year. There have been both high run-off years and years when 'adverse' water conditions prevailed. The decision in this study was to use an 'adverse' water year and achieve an additional degree of conservatism in the results. The choice was made to use water conditions during that 'water year' from August 1928 to July 1929. It should be noted that the August to July definition of a 'water year' is the definition employed by the Army Corps and may not correspond to definitions employed elsewhere.

The results from the analysis are summarized in Table 15. The data in this table indicate that of the eight reservoirs reviewed the various pricing policies or schemes lead to seasonal water use and hence seasonal reservoir elevations of which the maximum is the same (column 1 in the table) and the minimum levels are increased by, in some instances, as much as twenty feet. The second column in the table indicates what the seasonal reservoir minimum elevations would be if no alteration in the original prices were allowed.

The findings with the Washington State Reservoir model are not reported here but demonstrate the potential for much larger effects. The requirement that only pricing implications for load shape be evaluated and thus that the total energy supplied over the year remain constant was dropped. With this condition, the implications of pricing schemes for reducing overall energy demands as well as changing seasonal load shape lead to the result that many reservoirs may contain as much as 50-80 more feet of water during periods of minimum elevation. It must be emphasized that a number of issues remain to be studied in this part of the work and these particular results must be treated with caution.

TABLE 15: Seasonal Maximum and Minimum Elevation Levels for Selected Reservoirs: August 1928 - July 1929 Water Year[1]

Reservoir	Maximum Level	Minimum Levels								
		original condition	flat-rate pricing & two-part schedule with a revenue constraint				flat-rate pricing with a revenue constraint			
			$\varepsilon_p=-.2$		$\varepsilon_p=-.6$		$\varepsilon_p=-.2$		$\varepsilon_p=-.6$	
			STD	S	STD	S	STD	S	STD	S
Ross	1602.5	1491.5	1513.1	1513.1	1511.4	1511.0	1502.8	1503.5	1509.9	1509.7
Cushman No. 1	738.0	674.0	673.7	674.0	686.2	686.2	673.7	673.8	686.2	686.2
Libby	2459.0	2383.4	2383.5	2383.8	2388.4	2388.3	2383.5	2383.6	2388.1	2388.0
Duncan	1891.9	1809.6	1822.9	1823.3	1822.0	1821.8	1816.7	1817.1	1821.2	1821.0
Arrow	1444.0	1378.0	1387.0	1387.5	1386.0	1385.8	1380.5	1380.9	1385.2	1385.0
Hungry Horse	3560.0	3503.6	3503.7	3503.9	3514.1	3513.9	3503.7	3503.8	3513.3	3513.3
Dworshak	1599.2	1499.0	1509.3	1509.4	1509.5	1509.5	1508.7	1509.4	1509.4	1509.4
Mossyrock	778.5	676.3	687.8	688.7	697.2	697.2	687.1	688.0	697.2	697.2

[1]Reservoir elevations are measured in feet. ε_p is the notation for price elasticity of demand. STD indicates the presence of time-of-day and seasonal pricing and S indicates the use of seasonal pricing methods only.

CONCLUSIONS

This study clearly establishes the benefits of seasonal, peak-load pricing in Northern Idaho. It also shows that a two-part schedule pricing scheme with a 'usage' price for power set at marginal cost in each pricing period and with a certain rebate or 'dividend' program accomplishing an equity adjustment between stockholder and customer represents the optimal pricing strategy.

While caution must be employed in interpreting the results for hydro system operation, it is clear that important effects can be expected in terms of the seasonal operation of certain reservoirs. It must be understood that these effects are conditional on the representative nature of the North Idaho example for the entire Northwest region and conditional on the adoption of appropriate pricing policy by utilities not only in Idaho but elsewhere in the Northwest. Nevertheless the effects measured in this report should be viewed as conservative with actual responses anticipated to be larger.

FOOTNOTES

		Page
1.	Coordination arrangements are spelled out in (23)...............	1
2.	See (2), (6), (27), (30). These are only some of the relevant references. A bibliography would be lengthy...........	1
3.	Some estimates of the importance of irrigation - electric power generation trade-offs are provided by (27)................	1
4.	See the discussion in (15)......................................	6
5.	These figures are illustrative of figures 4 and 5, respectively...	7
6.	See (20) and (21)...	8
7.	See also (20) and (21)..	8
8.	See (3), (14), and (25). The Northwest Energy Policy Project employs a methodology virtually identical with that in (25).....	20
9.	The importance of bias in research based on state data is one topic in (14)..	22
10.	The relationship between long and short run price elasticities is established in (16).....................................	23
11.	(4) provides a survey of some evidence on load shape for different customer classifications..............................	24
12.	See (20) and (21)...	28
13.	To the extent that spillage is reduced there will be some increase in the generation of energy...........................	28
14.	The use of LOLP's is complicated by the result that LOLP's themselves will end up being functions of the prices set. This is simply because the probability of loads invading reserve margins will differ when loads are different - certainly with new prices loads will be different...............	30

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APPENDIX

NORMATIVE ANALYSIS
OF
PRICING METHODS

Introduction

Normative analysis of pricing policy requires determination and comparison of pricing methods under different price structures such as flat-rate or two-part schedules. It also requires the assumption of rational customer behavior. The appropriate pricing method under a particular price structure is selected as that method which maximizes the total of customer satisfaction and benefits to the firm in supplying the customer. The individual customer--firm exchange is the focus of the analysis. Flat-rate and two-part schedule price structures differentiated by the presence of a revenue constraint will be the subject of this appendix. While the customer considered in each case is a household or residential electric customer, the final results would be the same for electric customers who were commercial or industrial enterprises.

The household or residential electric customer is assumed to consume n commodities over the course of the year, where k of these commodities are quantities of electricity consumption in each of k time or pricing periods into which the year is partitioned. The households' satisfaction is then represented by an ordinal utility function:

$$U\,(q_1,\ \ldots,\ q_n) \tag{A-1}$$

where $q_1, .., q_k$ quantities of electricity consumption in each of k pricing periods

$q_{k+1}, .., q_n$ quantities of n-k other products consumed in the year

The problem of durable goods is ignored by assuming that the analysis is a long-run or steady state analysis.

Let

M = income budgeted for expenditure in the year

$p_1, .., p_n$ = prices, respectively, of the n goods

Flat Rate Pricing With No Revenue Constraint

A flat rate pricing structure allows electricity prices to differ among pricing periods but requires that in each period only one price exists.

Rational customer behavior is defined as that choice of $q_1, .., q_n$ which maximizes satisfaction defined by (1) subject to the budget constraint.

$$M = \sum_i p_i q_i \tag{A-2}$$

Rational behavior then implies that the choice of the quantity of each product depends on the price of that product, all other prices, and budgeted income.

$$q_i = q_i\ (p_1, .., p_n, M) \qquad i = 1, .., n \tag{A-3}$$

Variation in quantities purchased and, hence, variation in household satisfaction brought on by price variations is analytically derived as the total differential:

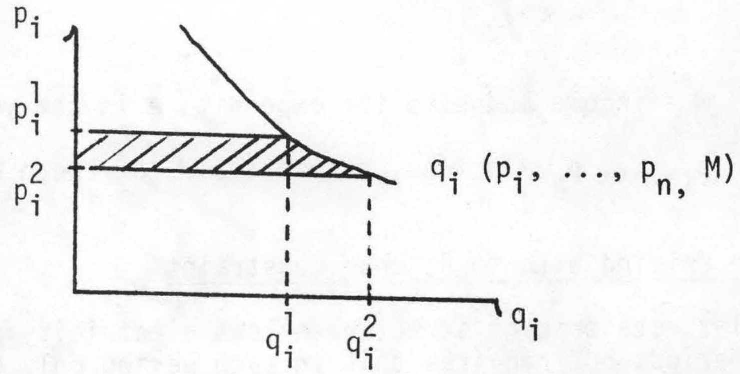
$$d\ U(q_1, \ldots, q_n) = -\lambda \sum_i q_i dp_i \tag{A-4}$$

λ is interpreted as the marginal utility of income, i.e., it is the amount by which satisfaction would increase if an additional dollar of income were available and allocated across purchases. λ would be expected to be variable both under different economic conditions facing the customer and across customers. Eliminating the issue of equity from the pricing problem is accomplished by arbitrarily setting $\lambda=1$. Thus, the effect on customer satisfaction of variation in the i^{th} price becomes

$$\frac{d\ U}{d\ p_i} = -q_i \tag{A-5}$$

In a discrete framework where price would vary discretely from p_i^1 to p_i^2, the effect on satisfaction would be graphically represented by the shaded area in Figure E-1..

Figure A-1



In this example the customer's satisfaction increases in dollar amount equal to the shaded area.

The problem of the optimal pricing method with a flat-rate pricing structure and no revenue constraint is then to find that method for choosing $p_1, .., p_k$ such that when prices are chosen in this way the total of utility profits (Π) and customer satisfaction is maximized. Utility profits are defined by

$$\Pi = \sum_{i=1}^{k} [p_i q_i - C_i(q_i)] \tag{A-6}$$

Where $C_i(q_i)$ is the total cost of supplying q_i in the i^{th} pricing period and where q_i, because of rational household behavior, depends on all prices and income.

Then the problem is formally

$$\max_{p_1, .., p_k} \quad W = \Pi + U(q_1, .., q_n) \tag{A-7}$$

The necessary conditions for obtaining a maximum can be shown to be

$$p_i = \frac{d\, C_i(q_i)}{dq_i} \qquad i = 1, .., k \tag{A-8}$$

Thus, the pricing method with a flat rate pricing structure and no equity consideration is purely the rule of economic efficiency that price equal marginal cost in each pricing period and for each customer.

It must be kept in mind that marginal costs are different in each pricing period and are also different typically in supplying customers of different types.

Flat Rate Pricing With a Revenue Constraint

The problem is identical to that above with the exception that a notion of equity is introduced by the constraint that no more than a fixed revenue of R^o is allowed the firm from the customer's purchases over the k pricing periods. That is, the constraint is imposed which requires

$$R^o = \sum_{i=1}^{k} p_i q_i \tag{A-9}$$

The problem is then formulated as

$$\max_{p_1, \ldots, p_k, \eta} \quad W = \Pi + U + \eta \, [R^o - \Sigma_1 \, p_i q_i] \tag{A-10}$$

where η is a variable in the problem.

The necessary conditions for obtaining a maximum, and hence the implied pricing method, are more complicated. These conditions are given by

$$\sum_{i=1}^{k} [(1-\eta)p_i - MC_j] \frac{dq_i}{dp_j} \qquad -\eta \, q_j = 0 \qquad j = 1, \ldots, k \tag{A-11}$$

$$R^o - \sum_{i=1}^{k} p_i q_i = 0 \tag{A-12}$$

where

$$MC_i = \frac{dC_i(q_i)}{dq_i}$$

These pricing rules represent an application of what is known in the Economics literature as Ramsey Pricing.

<u>Two-Part Schedule With Revenue Constraint</u>

The two-part schedule, or the pricing structure employed here, involves a fixed charge or rebate in each pricing period and a "usage" price. Therefore, in the i^{th} pricing period the customer's bill for consuming q_i kilowatt hours is defined as

$$c_i + p_i q_i \tag{A-13}$$

where $p_i > 0$, but c_i could be negative (rebate), positive (customer charge), or zero.

Rational customer behavior is somewhat differently represented here as the household's budget contraint is given by

$$M - \sum_{i=1}^{k} c_i - \sum_{i=1}^{n} p_i q_i = 0 \tag{A-14}$$

Rational behavior implies that the quantity of each product purchased depends on prices, budgeted income, and the c_i's as

$$q_i = q_i \left(p_1 \ldots, p_n, M - \sum_{i=1}^{k} c_i\right) \qquad \text{(A-15)}$$

$$i = 1, .., n$$

With this new pricing structure, rational customer behavior and a revenue constraint designed to allow implementation of the "Regulatory" concept of equity, the problem becomes

$$\max_{p_1, \ldots, p_k, c_1, \ldots, c_k, \eta} \quad W = \Pi + U + \eta \left[R^o - \sum_{i=1}^{k} (c_i + p_i q_i)\right] \qquad \text{(A-16)}$$

That is, in addition to the new formulation (15), the revenue constraint is also rewritten as

$$R^o - \sum_{i=1}^{k} (c_i + p_i q_i) = 0 \qquad \text{(A-17)}$$

The necessary conditions for a maximum, and thus the implied, pricing method are given, after some simplification, by

$$\sum_{i=1}^{k} (p_i - MC_i) \left(\frac{dq_i}{dp_j} - q_i \frac{dq_i}{dc_j}\right) = 0 \qquad \text{(A-18)}$$

$$j = 1, .., k$$

$$R^o - \sum_{i=1}^{k} c_i - \sum_{i=1}^{k} p_i q_i = 0$$

Under reasonable assumptions these conditions further reduce to

$$p_i = MC_i \qquad i = 1, .., k \qquad \text{(A-19)}$$

$$\sum_{i=1}^{k} c_i = R^o - \sum_{i=1}^{k} p_i q_i \qquad \text{(A-20)}$$

That is, the appropriate pricing method is to set the usage price in each period equal to marginal cost (MC) and then choose a configuration of rebates for the k pricing periods so that they total to the amount of revenue necessary to return to the customer in order that the revenue constraint be satisfied. There is no implication as to what configuration of rebates should be used, and with this flexibility there are possibilities available that could be selected to achieve other purposes.

Conclusions

The last pricing structure considered was a more general structure than any of the other structures and, therefore, the pricing methods suggested by it must be considered better or superior to the other cases.