REVIEW OF RATE STRUCTURES
FOR WASHINGTON INVESTOR OWNED
ELECTRIC UTILITIES

prepared for the

WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

by

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in behalf of

THE NATIONAL REGULATORY RESEARCH INSTITUTE
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FOREWORD

This report was prepared by Economic and Engineering Services, Inc. for The National Regulatory Research Institute (NRRI) under Contract No. EC-77-C-01-8683 with the U.S. Department of Energy (DOE), Economic Regulatory Administration, Division of Regulatory Assistance. The opinions expressed herein are solely those of the contractor and do not reflect the opinions nor the policies of either the NRRI or DOE.

The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utilities regulation.

The NRRI appreciates the cooperation of the Washington Utilities and Transportation Commission with the contractor in preparing this study and for their permission to make this information available to others interested in regulatory affairs.

Douglas N. Jones
Director

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FOR WASHINGTON STATE INVESTOR OWNED UTILITIES

AN EXECUTIVE SUMMARY

Purpose

The purpose of this study was to review the existing rate structures of three investor owned electrical utilities in Washington State and evaluate how the rates of each utility:

1. Reflects cost of service, both estimated average and marginal;

2. Effects energy conservation, defined as the affect of a rate on consumer demand given estimated elasticity of demand;

3. Relates to allocational efficiency understood as an economic term implying the optional use of resources due to marginal cost prices.

Methods

Because this review was performed as a limited technical assistance project to the Washington Utilities and Transportation Commission, a full study of how each utilities' rates relate to the three criteria set out above was not undertaken. In lieu of this, each utilities' class of service rate levels were analyzed, classified and compared with estimated costs of service expressed at traditional and marginal levels.

The merits of alternative rate structures were next considered to explain some of the assumptions and pitfalls surrounding rate reform in pursuit of conservation and efficiency.

In the report, the effects of various rate structures and levels are reviewed to determine how each might be expected to relate to energy consumption.

The report also provides conclusions and recommendations for obtaining the three goals identified in the purpose statement.

Findings

Section I of the report reviews the scope of work, summary of work and overview of conclusions and recommendations.

Section II is a review of investor owned electric rate schedules and structures in Washington State. This review concludes that the design of rate structures is not consistent for the three utilities. Each utility has flat or inverted rates for residential service, while general service and large power rates are flat or declining. It appears that rates and charges of the utilities may not be cost based whether traditional or marginal costs are considered as the relevant standard. This conclusion is based on estimated costs compared to filed rates. In several cases, general service and pumping rate schedules do not appear to be voltage differentiated. A number of opportunities exist for rate consolidations and alternate rate designs to reflect cost separations available. Several rate schedules could benefit from simplifications in terminology, conditions and removal of obsolete terms.

Section III is a comparison of existing rate structures and levels with estimated embedded and marginal costs of service for the three investor owned utilities. Since these utilities were not historically required to submit cost of service studies, estimations of both embedded and marginal costs were prepared for several major customer classes, but not all classes. These estimates of cost are, necessarily, approximations used to suggest the general direction and magnitude of the differences between costs and the present rates charged by the utilites. In a series of exhibits, a number of comparisons are made. These comparisons show that the utilities' present rates are substantially lower than they would be if the estimated marginal costs were applied.

If average embedded costs are applied, it would appear that residential consumers are not paying their costs of service in present rates for all three utilities. These deficiencies are accounted for by the general service-small and general service-large power customer classes. When viewed as the ratio of cost to rate, these differences are quickly evident. Estimated average costs for residential uses are 30% to 100% greater than present rates, while in the other classifications existing rates are 6% to 24% greater than average costs. In essence, subsidies may exist for residential users.

Section IV of the study considers the impact of alternative rate structures on electrical consumption. In this section of the study, the topic of consumer sensitivity to various rate structures and levels is considered. In general, this analysis is subject to empirical research on consumer behavior. On the other hand, a number of helpful insights are presented which suggest the nature of the problem and general behavioral patterns of consumers under certain conditions. Elasticities for the residential, commercial and industrial customer classes are outlined. It is shown that the short run response is significantly less than the long run sensitivity. To fully realize the final impacts of rate structure, it is concluded that a period of time approaching 20 years may be necessary. The sensitivity of various industrial consumers seems to vary by standard industrial code or type of industry. The industrial pattern of response is not, however, greatly different from other consumers.

The questions of response to time differentiated rates remains to be dealt with definitively. There is some evidence of time period consumption sensitivity which should be considered; however, there is no safe generalization which represents this research. Some system specific research suggests that sensitivity to time of use rates varies across customer classes. In addition, commercial and industrial groups may exhibit different sensitivities to time variant rates. This research is presented in table form in the report.

Section V considers the general economic problem of allocational efficiency in rate structures. This section is a detailed exposition of problems and general conclusions. The upshot is that marginal cost rates are considered attractive in theory, but subject to serious reservations when implemented in an economy where marginal prices are not universal. The conclusion of the analysis is to caution that marginal cost rates may hurt as much as they enhance allocational efficiency, and that one need be highly circumspect in rate recommendations.

It is noteworthy that simply increasing rates or prices as a means of rationing demand for electrical service is questionable since economic efficiency may not be served. To raise rates in the name of pursuing economic efficiency without fully considering the side conditions for realization of increased efficiency is, of course, extremely doubtful policy.

Lifeline rate research seems, by contrast, to be reasonably well settled. It appears that lifeline rates, which provide services below costs for some units of consumption, may be justified on political grounds. Uniformly, economists consider subsidy rate levels to be undesirable. Alternatives, such as side payments to the low income, are the preferred method of subsidizing consumption for selected groups. This is especially desirable where consumers are highly sensitive to price and may construe a lower than cost price as an incentive to expand consumption. And, if consumers are not price sensitive, there is little justification for a lifeline rate. Perhaps the most important point to be retained is that lifeline concepts leave little to recommend them. As a rule, the concept encourages use, does not reflect cost and understandably results in misallocations of resources.

Section VI contains conclusions and recommendations. In general, the rates of the investor owned utilities in Washington for the customer classes reviewed were not cost based compared to the estimated average costs. Present rates are also substantially less than the estimated marginal costs for these utilities. Moreover, subsidies seem to exist between customer classes. From an administrative perspective, the tariff schedules could benefit from consolidation and clarification as well as modernization of terms.

It is concluded that the benefits of alternative rate designs are at very best open to substantial question if economic efficiency is the prime goal. It is readily conceded that higher prices will ration demand and therefore conserve energy as compared to lower price levels. What is not clear is whether society will be better off. Marginal cost rates can be said to contribute to allocation efficiency only where the economic system is marginally oriented in all consumption decisions. Time differentiated rates of various kinds may have benefits insofar as they can give better signals to consumers as to the costs of service than do average cost rates. However, if time differentiated prices are not marginal, there is no way of preferring such rates over other alternatives purely on the grounds of allocational efficiency.

The study confirms that consumers should be expected to be price sensitive over the range of prices reviewed, and that rate structure and rate levels can be designed in various ways to affect consumption if it can be determined which direction one wishes to move. In this effort, the contribution of economic research to rate design is to assist the policy maker in pursuing goals arrived at by means other than economic insight.

CONCLUSIONS AND RECOMMENDATIONS

The study concludes the following in regard to the three Washington Utilities:

1. CONCLUSION: Compared to the estimated costs of servies, the rates of the three investor owned utilties are more or less typical of the United States electrical industry. There would be material benefit in consolidation, simplification and modernization of rates in all utilities.

   RECOMMENDATION: The Washington Utilties and Transportation Commission (WUTC) may desire to review the benefit of greater standardization of utility rate structures in which consolidations, simplification and justification of specific design and level differences are explored. Such steps would make possible the comparison of utilties, would likely enhance consumer response to rates and could reduce the costs of rate administration by the utility.

2. CONCLUSION: It would appear that none of the three utilities has set rates based on an awareness of average embedded costs of service. In general, each utility appears to be charging residential users somewhat less, in proportion to cost, than is charged general service and industrial customers. This conclusion suggests that rate equity, based on average embedded cost recovery, may require attention, if rate equity at this cost level is desired. A policy of offering residential service at lower rates is common in the United States.

   RECOMMENDATION: The WUTC may desire to explore whether each consumer class is paying its average embedded costs of service and the proportion of cost each pays. This information would provide a measure of rate equity, if it is first assumed that costs of service have been allocated properly. A number of allocation methods are available for use in cost of service studies. Selection of allocation methods should be based upon an understanding of the operational characteristics of each utility and those served.

   Also of concern is the problem of customer class definition and discrimination (due, undue or gross) among rate payers in the same class. Classes should reflect more than common voltage levels or consumption characteristics which have historically been used as class determinants, and still might be used, if cost related. Today, classes are becoming more rigorously defined based on the costs incurred in service to the class. If a classification is cost rational and rates are well related to class costs of service, legal discrimination problems as traditionally defined can be reduced or avoided. In this area of inquiry, it is helpful to recall two points: First, different unit rates for service between different classes of customers should be justified by different unit costs of service between the classes. Second, class definition by the utility (however done), should carry some measures of dispersion among members of the class as an indication of how generally the criterion apply. For example, if the average demand in a class of service is 10 and that number is employed to allocate capacity to the class, it is important to know what the class size is and the standard deviation of the demand within the class. The problem to be dealt with is appropriateness of class given the criterion employed. Today many load research programs permit good answers to these questions.

3. CONCLUSION: It would appear that none of the utilties has set rates with respect to marginal costs of service. The existing rates of each utility are substantially lower than the range of marginal costs estimated for these utilities. This suggests that consumers of electrical services in Washington State may be using more energy than would be the case if marginal cost based rates were employed. Depending on consumer price sensitivity, this "overconsumption" of energy could be substantial. Long run price elasticity of demand estimates seem to suggest (all else equal) that over the relevant adjustment period each percentage point of real price increase will be met with an equal, or greater, reduction in the quantity of energy demanded. Therefore, while the price induced changes in electricity consumption maybe possible, the desirability is not so readily seen.

RECOMMENDATION: The WUTC may desire to explore, in addition to marginal costs, a range of alternatives to full marginal cost prices. It is generally acknowledged that marginal costs are justified as benefitting allocational efficiency only under rigorous assumptions. Marginal cost rates might be charged ratepayors as a way of more accurately signaling costs of service and enhancing consumer awareness. Such policy would accept that allocational efficiency is not a feasible goal and would instead seek only to let each consumer pay his way based on current costs.

The implications of charging current cost rates (an alternative to future oriented marginal costs) turns in large measure on consumer price sensitivity. If consumer sensitvity exists, the quantity of electricity consumed will fall. This is in one view "conservation". Such conservation is not related to allocational efficiency; therefore, it is not known for certain whether society is benefitted. On the other hand, if energy saving targets exist, a price policy might be the most efficient means to obtain desired conservation levels.

Other alternatives to marginal cost rates can be examined for their contribution to providing more appropriate cost signals and for their impact upon conservation. Time differentiated average cost rates might be more appropriate for consumers where significant peaks exist. A higher rate during peaks could be a means of informing consumers what present consumption patterns will lead to in the future. This alternative rate design collects average costs, but does so by varying rate levels in time. If there is period price sensitivity, the quantity sold on-peak may fall, or stabilize, and revenues be reduced, or plateaued. Off-peak use may grow. Such alternatives to marginal cost are, therefore, not risk free and may have uncertain effects on net conservation as well. These problems notwithstanding, there are a number of reasons other than economic efficiency for reviewing the contribution of each to policy goals.

None of the alternative rate designs can be claimed to have a known effect on allocation efficiency in a mixed economy; therefore, the pursuit of this goal should be set aside as a justification for this type of rate reform.

4. CONCLUSION: There are reasons to believe that consumers of electrical services in the three investor owned utilities would exhibit price sensitivity of the general direction and magnitude defined in the study. Nonetheless, the state of current research suggests that no policy should be adopted based on the accuracy of elasticity estimates alone. Caution and gradual adjustment of rates making limited use of elasticity data is concluded to be the best policy. The dynamic adjustment process of consumers suggests the need for a long term price perspective; time is required for the full realization of price impacts upon consumption.

RECOMMENDATION: Whether prices of electrical service have any allocational effect depends on the price elasticity of demand. If consumers are not influenced by price in making consumption decisions, demand is totally inelastic. This means that there is no price which will affect consumer decisions. Since total inelasticity is improbable, economists are typically interested in elasticity measures. Such estimates are recommended for Commission consideration because they are reasonably consistent in showing the direction of magnitude of consumer price sensitivity. Thus, elasticity estimates suggest the change in consumption that may be expected if real price levels are varied in specific ways. In each instance, one can estimate the increased use, or reduced use, which will result from a change in price policy.

An investigation of price sensitivity is valuable in two added respects. Price elasticity data is also helpful in suggesting pro forma revenues, and the impact of a rate on consumer budgets.

Most utilities should be able to estimate the price elasticity of various consumer groups by making use of load data. Appropriate load research and forecasting programs would routinely provide these estimates.

To obtain cost-related, energy-conserving, efficient rates in Washington State, a major increase in the data collected and considered in the regulatory process is required. Clearly, cost of service studies, both average and marginal, are needed. Also necessary are load forecasts, elasticity estimates and service expansion plans and costs. With such data, a major effort can be mounted by the utility, staff and the Commission to determine what rate policies are supportive of goals under consideration. Currently, absence of such information hinders such a review.

REVIEW OF RATE STRUCTURES

FOR

WASHINGTON STATE INVESTOR-OWNED UTILITIES

STUDY

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SECTION I

INTRODUCTION

This study was undertaken under a contract with the National Regulatory Research Institute (NRRI) which provided technical assistance to the Washington Utilities and Transportation Commission (WUTC) for a review of the current rates of three investor owned electrical utilities in Washington State. The study was commissioned in April 1979 and completed in May 1979.

The purpose of the study was to review the existing rate structures of three investor owned utilities to evaluate how each utililty rate structure:

1. Reflects cost of service, both estimated average and marginal;

2. Effects energy conservation defined as the affect of a rate on consumer demand given an estimated elasticity of demand;

3. Relates to allocational efficiency understood as an economic term implying the optional use of resources due to marginal cost pricing.

Methods of Study and Limitations

The study was limited in scope and the conclusions which may be drawn from this work are extremely limited and highly general. No cost of service studies were performed, nor were cost of service studies for the relevant utilities available. The Washington Commission has not historically required the utilities to file cost studies in the course of rate proceedings. Accordingly, Economic and Engineering Services, Inc., the Consultant, prepared a series of estimates of costs of services which reflect cost study results for utilities having technology and load characteristics similar to those under review. The Consultant does not consider the estimates to be more than suggestive of the costs of service of the three Washington utilities. Before any conclusions can be reached on the three criteria set out above, it is necessary for all three utilities to provide both average embedded and marginal cost studies. The value of this study stems chiefly from the benchmarks it provides. The study suggests which questions may be most relevant in attempting to deal with the three criteria outlined and the general direction and magnitudes of differences between rates and costs. Beyond these limits, the study provides little specific assistance in reaching rate decisions based on the three criteria noted earlier.

The study was designed to provide to the WUTC an analytical perspective which should prove beneficial in reviewing the conservation and efficiency questions. As the study shows, much remains to be done in rate research in the United States. In all cases, however, a central theme is sounded: caution. The rush to energy conservation by making use of consumer price sensitivity has no antecedent in allocational efficiency. The teaching of price theory in economics is clear and straightforward. When all prices are marginally determined, conservation is at its economic optimum and no conservation policy apart from a marginal price policy is needed, and if pursued will lower welfare. Conversely, when prices are other than marginal, there will be over- or underconsumption of goods and services as compared to the marginal condition. Where prices are below marginal costs, there will be overconsumption compared to the marginal, and a separate conservation policy may indeed be a means of enhancing allocational efficiency, or reducing the demands for resources to produce electrical services. Still, as clear as these propositions seem in the abstract, there is room for caution because one does not know how much to conserve or what dislocations may result from the conservation. The fundamental problem is that a nonmarginal economy may function with a large number of inefficient allocational relationships in a relatively stable and socially satisfying manner. As a result, any allocational changes will raise questions about who is hurt and who is helped. Unfortunately, economic theory and research has little to offer in this setting.

Since it is generally acknowledged that the United States economic system is not marginal or even a close approximation, there is every reason to approach rate reform policies with caution. As past experiences have suggested, the United States is an energy sensitive economy. Any change in the terms of energy transactions can affect the user and the larger economy. In a non-marginal market setting what is not clear is whether the economy will be harmed or enhanced. This study provides no insight at this level of policy analysis. Instead, the study reviews the policy, theory and research which makes it possible for policy makers to attempt to pursue their goals by moving generally in the direction of change desired.

CONCLUSIONS

The study concludes the following in regard to the three Washington Utilities.

1. CONCLUSION: Compared to the estimated costs of servies, the rates of three investor owned utilities are more or less typical of the United States electrical industry. There could be material benefit in consolidation, simplification and modernization of rates by all utilities.

2. CONCLUSION: It would appear that none of the three utilities has set rates based on an awareness of averge embedded costs of service. In general, each utility appears to be charging residential users somewhat less, in proportion to cost, than is charged general service and industrial customers. This conclusion suggests that rate equity, based on average embedded cost recovery, may require attention, if rate equity at this cost level is desired. A policy of offering residential service

at lower rates is common in the United States.

3. CONCLUSION: It would appear that none of the utilities has set rates with respect to marginal costs of service. The existing rates of each utililty are substantially lower than the range of marginal costs estimated for these utilities. This suggests that consumers of electrical services in Washington State may be using more energy than would be the case if marginal cost based rates were employed. Depending on consumer price sensitivity, this "overconsumption" of energy could be substantial. Long run price elasticity of demand estimates seem to suggest (all else equal) that over the relevant adjustment period each percentage point of real price increase will be met with an equal, or greater, reduction in the quantity of energy demanded. Therefore, while price induced changes in electricity consumption may be possible, the desirability is not so readily seen.

4. CONCLUSION: There are reasons to believe that consumers of electrical services in the three investor owned utilities would exhibit price sensitivity of the general direction and magnitude defined in the study. Nonetheless, the state of current research suggests that no policy should be adopted based on the accuracy of elasticity estimates alone. Caution and gradual adjustment of rates making limited use of elasticity data is concluded to be the best policy. The dynamic adjustment process of consumers suggests the need for a long term price perspective; time is required for the full realization of price impacts upon consumption.

SECTION II

REVIEW OF INVESTOR OWNED UTILITY ELECTRIC RATE SCHEDULES

INTRODUCTION

This section reviews the rate schedules and rate structures applied to customer groups of the three private electric utilities regulated by WUTC: Puget Sound Power and Light Company (Puget Power), the Washington Water Power Company (WWP) and the Pacific Power and Light Company (PP&L). The review is conducted to provide insights about the current status of rate schedules and rate structures of the three utilities.

Items of interest in the review of rate schedules and rate structures include definitions of customer classes of service relative to existing rate schedules, potentials for rate consolidation and simplification, consistency in rate structure, application to customer classes, and probable relationship of existing rate structure to cost of service.

METHODOLOGY

The review of rate schedules and rate structures herein was conducted through detailed examination of existing rate schedules currently in effect for the three private utilities. The results presented herein reflect analyses of rate schedules combined with judgmental interpretations made by the consultant using the definitions and assumptions stated below.

Definitions of Rate and Cost Terms

Definitions of terms used in this section pertinent to the review of rates are as follows:

1. Customer Cost. A cost which varies with the number of customers on the electric system. It may include meter reading, billing and other variable cost, as well as a customer allocated fixed cost associated with the distribution system plant. It is referred to as a "basic charge" in the rate schedules of the three utilities examined.

2. Demand Cost. A cost which varies with the capacity requirements, or size of facilities, needed to provide electric service to customers.

3. Energy Cost. A cost which varies with the energy production or consumption of customers. Fuel costs are typical examples of energy costs.

4. Declining Rate. A demand or energy charge whose unit cost declines as capacity or energy requirements increase.

5. Flat Rate. A demand or energy charge which is constant regardless of capacity or energy requirements.

6. Inverted Rate. A demand or energy charge whose unit cost increases as capacity or energy requirements increase.

Assumptions

The review and interpretation of rate schedules and rate structures of the three private utilities regulated by WUTC are based upon the following fact assumptions and policy guidelines which reflect broadly the industry and the principles generally applied to rate making.

1. There are basically five classes of service which are generally applicable to most utility customers and utililties. They are:

   a) Residential - secondary voltage (120/240 volts)

   b) General service (commercial and industrial) - secondary voltage (below 2.4 KV)

   c) Large power service (commercial and industrial) - primary voltage (2.4 to 13.8 KV)

   d) Irrigation (pumping) - secondary voltage (below 2.4 KV)

   e) Lighting (security, street and traffic)

   Some exceptions occur and may be appropriately defined by separate rate schedules.

2. Consolidation of rates into fewer schedules and simplification of rate schedule definitions and charges is a widely recognized goal benefitting all through better understanding, careful choice and lower costs.

3. Rate structure with reference to flat, inverted or declining forms should be consistently applied to various customer classes unless it can be sufficiently demonstrated that the costs of providing service to a class varies from the structure of the costs of providing service to another class.

4. Rate structures should reflect costs of service as closely as possible. The selection of which cost definition (average, marginal, ect.) to be pursued is a matter of policy and goals in the regulatory jurisdiction. What is sought here is a rational relationship between prices and costs which will enhance choice making for all.

5. Rate and schedules should separately reflect as specific components demand, energy and customer costs of service, thus allowing consumers and regulator to relate costs and consumer behaviors. The result sought is enhanced decision making for all.

COST OF SERVICE STUDY REQUIREMENTS

At the present time, WUTC does not require the three regulated electric utilities under its jurisdiction to file cost of service studies with rate applications or documentation on revenue requirements and rate designs. Although some cost of service work has probably been explored within each utility, evidence that the rates presently in effect are cost-based is not available. Pursuant to the scope of services for this study, estimates were made of the average embedded and marginal costs of service for major customer classes.

RATE REVIEW FOR PUGET SOUND POWER AND LIGHT

Rate schedules at Puget Power are applicable to the following customer classes: residential, commercial, industrial and lighting. These individual tariffs are listed and described in Exhibit #1.

Residential Service

Residential rates are applied through Schedules 4, 6 and 7 for Limited Residential Water Heating Service, Limited Water Heating Service and Residential Service respective. Schedule 4 is a water heating rental rate with energy charges equal to Schedule 7. New service is not available on Schedule 6 which is applicable for water heating requirements in addition to normal domestic use. Single and three phase service is available at the secondary voltage level under this tariff. Schedules 6 and 7 have a basic charge (similar to a custmer charge) of $3.45 per month for single phase service and $13.00 for three phase service in addition to energy charges. Schedule 6 applies a flat energy charge. Schedule 7 applies a two-step inverted energy rate structure. Accordingly, higher use residential customers must pay a higher unit price as consumption increases. The flat energy rate on Schedule 6 is lower than the end block of Schedule 7.

General Service

General Service (commercial) rates are applied in Schedules 19, 24, 28 and 29 for Limited Commercial Water Heater Rental Service, General Service, Commercial Service and Seasonal Service-Off Peak respectively. Schedule 28 is closed to new service. Schedule 19 is a water heating rental rate with energy charged according to Schedule 24. Single and three phase service is available at the secondary voltage level. All general service schedules apply a basic charge of $3.45 per month for single phase service and $13.00 per month for three phase service, similary to the basic charge applied to residential customers. Schedule 24, General Service, applies an inverted demand charge for capacity requirements over 50KW. Energy charges on Schedules 24, 28 and

29 consist of declining two and three block rate structures.

Large Power Service

Two primary service rates for large power customers are applied through Schedules 31, Primary General Service, and Schedule 35, Seasonal Primary General Service Off-Peak. Schedules 31 and 35 apply a basic charge of $40.00 per month. This minimum charge for these schedules is the basic charge plus the monthly demand charge. The demand charges for Schedules 31 and 35 are flat charges of $2.05 and $.80 per KW of demand, respectively. Schedule 31 has a two block declining energy charge while Schedule 35 has a flat energy charge.

An interruptible rate schedule exists for total electric schools served at primary voltage. Schedule 43, applicable to public educational institutions, applies a flat demand charge of $.80 per KW of monthly demand and a flat energy charge of .99¢ per KWH.

Puget Power has several rates in effect for high voltage industrial customers. They are Schedules 39, 46 and 49. Service on these rate schedules is available from 13.8-50.0 KV. Schedule 39 is an Optional High Voltage General Service rate schedule which applies a flat demand charge of $1.47 per KW and a flat energy rate of .505¢ per KWH. Schedule 46 is a High Voltage Interruptible Service rate with no demand charge and declining energy charge per KWH. Schedule 49 is a High Voltage General Service rate with a flat demand charge of $2.162 per KW and a flat energy charge of .505¢ per KWH.

In addition to the preceding rate schedules, Puget Power has five rates for Lighting customers which provide for flat rates for each type of lighting.

RATE REVIEW FOR WASHINGTON WATER POWER

There are ten different rate schedules at WWP. Of these ten rate schedules, five are applicable to lighting customers. These rate schedules are described in Exhibit II-2.

Residential Service

WWP applies one rate schedule, Schedule 1, to all residential customers with single phase service. This residential rate consists of a basic charge of $2.60 per month and a two block inverted energy charge.

General Service

Two rate schedules are applied to general service and commercial customers, Schedule 11 for General Service and Schedule 16 for Commercial Water Heating Service. Schedule 11 is applicable for customers receiving service at a secondary voltage level and at single or three phase service. These rates consist of a basic charge of $2.60 for single phase service and $7.60 for three phase service, a demand charge of $2.00 per KW for requirements in excess of 20 KW and a declining block energy rate structure of 1.99¢ for the first 3,000 KWH, 1.65¢ for the next 15,000 KWH and 1.27¢ for all additional consumption. Schedule 16, available for commercial water heating purposes, applies a basic charge of $2.60 per month and a flat energy charge of 1.354¢ per KWH.

Large Power Service

Two rate schedules exist for large general service customers at WWP, Schedules 23 and 25. Schedule 23, Large General Service, is applicable to larger general service customers with maximum demand requirements in excess of 50 KW at secondary or primary voltage levels. There is no basic charge applied on Schedule 23. The minimum charge is the demand charge, which consists of $100.00 for the first 50 KW and $1.15 per KW for all additional demand. A three block declining energy rate is applied in addition to the demand charge for Schedule 23. Schedule 25 applies no basic or demand charge. Charges for this tariff are applied through a declining block kilowatthour charge per kilowatt of demand.

Pumping Service

A pumping service rate for irrigation, municipal and other customers with water pumping requirements is applied through Schedule 32. This service is available at a secondary or primary voltage level. The minimum charge is $6.00 per KW of the highest annual demand. A demand charge is not directly applied; however, as energy is charged on a kilowatthour per kilowatt basis via four declining block rates.

Four lighting rate schedules, Schedule 40, 41, 42 and 44 are applied for street and security lighting. Each contains a considerable number of charges according to lamp type, lamp size, facilities used and ownership.

In addition to the charges noted above, an energy rate adjustment is applied to retail rate Schedules 1, 11, 16, 23, 25 and 32. This charge is currently .013¢ per KWH. WWP also assessed an additional energy surcharge for six months during 1977 of .124¢ per KWH to customers on these schedules.

RATE REVIEW FOR PACIFIC POWER AND LIGHT

Eleven rate schedules are applied by PP&L to its basic customer classes of service. These rate schedules are described in Exhibit II-3.

Residential Service

Residential rates are applied through two schedules, 16 and 18, for single phase residential service and three phase residential service respectively. These tariffs apply a basic charge of $3.00 per month and a flat charge for energy of 1.768¢ per KWH. The residential three phase service rate introduces an additional demand charge of $1.55 per KW of maximum monthly demand.

General Service

General service rates are applied through Schedules 24 and 33 for General Service and Partial Requirements Service. General service is provided at a secondary voltage for single and three phase services. Schedule 24 applies basic charges of $3.00 and $5.50 per month, respectively, for single and three phase service. To the basic charge, $1.50 per KW of demand in excess of 10 KW is added to compute the monthly minimum bill. If the customer's consumption exceeds the minimum charge, no demand charge is applied. Energy charges are based on a declining block rate structure which utilizes charges for both kilowatthours per kilowatt of demand and per kilowatthour. Schedule 33 is a special rate for standby service which applies a demand charge of $1.25 per KW and charges for energy equal to Schedule 36. The monthly minimum on this schedule is the demand charge for 100 KW. PP&L applies a separate rate schedule to churches having electric space and water heating. No new service is available under this rate. The rate applies a basic charge of $3.00 and $5.50, respectively, for single and three phase service. A flat energy rate of 2.08¢ per KWH is charged in addition. A separate rate also exists for Controlled Water Heating Service (Schedule 42) which is also not available for new service. This rate applies a basic charge of $3.00 per month and a flat energy rate of 1.88¢ per KWH.

Large Power Service

Three rate schedules are available to larger power customers. One schedule applies to customers with demand requirements in excess of 100 KW, and the other two schedules apply to customers with demand requirements in excess of 10,000 KW. The Large General Service - Optional 100 KW and over Schedule - applies a demand charge of $150.00 for the first 100 KW and $1.15 per KW for all additional monthly demands. Energy is charged via a five block declining rate structure. The rate schedules for large power customers over 10,000 KW of demand include the regular schedule and a standby schedule. The former, Schedule 48, applies a demand charge of $13,500 for the first 10,000 KW and $1.05 per KW for all additional demand. Energy charges are billed under a three block declining structure. The standby tariff, Schedule 47, charges $15,500 for the first 10,000 KW of demand and $1.25 per KW for all additional demand. Energy is charged via a four block declining energy rate schedule. Each rate schedule includes a discount for voltage delivery at 60 KV. Schedule 48 includes an additional charge of .15¢ per KW for deliveries at non-standard voltages.

Irrigation Service

PP&L applies a separate rate, Schedule 40, for service to irrigators and other pumping customers. The rates are applied during the irrigation season. The minimum charge is $17.00 per season per KW of demand, or $8.50 per KW per month for the highest demand reading. The monthly energy rate is a four block declining rate structure charging on a kilowatthour per kilowatt of demand basis. The rate, however, includes a maximum ceiling for charges on a monthly basis and limits the seasonal billing to $11.00 per kilowatt, 1.99¢ for KWH per kilowatt of demand and 1.29¢ for all additional kilowatthours.

Lighting

Lighting rates include Schedule 15 for Outdoor Area Lighting Service, Schedule 52 for Street Lighting Service - Municipal, Schedule 54 for Recreational Field Lighting - Restricted and Schedule 57 for Street Lighting Service. PP&L's lighting rates contain various rates and charges based upon lamp type, lamp size, facilities used and ownership.

GENERAL CONCLUSIONS

The preceding text describes in detail the current status of rate schedules and rate structures for the customer classes served by the three private utilities under the jurisdiction of WUTC. Based on this review, the following conclusions are presented for consideration:

1. Consistency is not evident in the design of rate structures of the three utilities for the various classes of service. In each utility, residential energy rates are flat or inverted. In contrast, general service and large power energy rates are flat or declining. In essence, residential customers are paying the same or more per unit of energy as consumption increases and general service and large power customers are paying the same or less per unit of energy as consumption increases. Such design differences invite questions about how they can be justified. This is not to say that these differences cannot be justified, only that they have not been. Equitable application of demand and energy costs should reflect a consistent view of the utility's costs in the design of rates.

2. Rates and charges applied in the three utilities' rate schedules do not appear to be cost based. This is illustrated by the inconsistency in energy rate designs among the residential, general service and large power customer classes. This discrepancy is also noticeable in the cases where basic charges for secondary service are similar for all classes of service when, in fact, a cost of service study yields different basic costs for all classes of service. Section III of this report will calculate the approximate ranges of energy, customer and demand costs which may be compared to the rates applied by the three regulated utilities reviewed above.

3. While the rate schedules of the three regulated electric utilities are basically separated by voltage level, there are still single rates applied to both the primary and secondary levels. General Service and Pumping Service rate schedules should be reviewed and their customers appropriately separated by voltage levels.

4. Considerable opportunity exists for rate consolidation in the three utilities. Investigations should be conducted for the following consolidation potentials:

   a. Residential rates at Puget Power and PP&L can be combined into a single rate schedule.

b. General service rates at Puget Power, WWP and PP&L can be combined into a single rate schedule. Existing schedules where no new service is allowed or special applications have been recognized (seasonal service, churches, electric space and water heating, or standby) should be integrated into a single rate schedule.

c. Seasonal or off-peak rate schedules should have their provisions integrated into one rate applicable to a single class of service.

5. Considerable opportunity also exists for rates to be redesigned so that they may more accurately reflect cost separations. For example:

   a. If average costs are used to design rates, demand, customer and energy charges should reflect allocated costs.

   b. Demand charges should be introduced in all General Service, Large Power and Pumping rates.

   c. Load factor rates, which charge on a kilowatthour per kilowatt basis and provide the customer with energy cost reductions as consumption increases, should be eliminated unless it can be demonstrated that such simultaneous recovery of the demand and energy components is cost tracking.

   d. Promotional rates should be eliminated and declining energy rate structures should be flattened in all general service, large power and pumping rates unless it can be demonstrated that declining block rate structures track appropriate cost components.

6. The rate schedules of the three electric utilities, particularly those of WWP and PP&L, should be reviewed for simplification of terminology and conditions. These schedules appear to contain words and provisions which are obsolete.

7. Time-of-use costing is nonexistent in all schedules of the three utilities, although some consideration has been given to seasonal differentiation and off-peak use.

The conclusions stated above are based on a review of rate schedules, and the rate goals as determined by the WUTC.

Exhibit II-1

Washington Utilities and Transportation Commission

Rate Schedule and Structure Review:

Puget Sound Power and Light Company

Rate Schedule No.	Rate Class Title	Voltage Level*	Minimum (M) or Basic (B) Charge	Demand Charges KW	Demand Charges $/KW	Energy Charges Kwh	Energy Charges ¢/Kwh	Rate Structure Classification
				Residential				
4	Limited Residential Water Heating Rental Service	S	$2.30-4.59 Based on Size**	None	None	0-1500 1501-Over	1.485¢ 1.677¢	Inverted-Energy
6	Limited Water Heating Service	S	$3.45(B) $13.00(B)	None	None	All	1.367¢	Flat-Energy
7	Residential Service	S	$3.45(B) $13.00(B)	None	None	0-1500 1501-Over	1.485¢ 1.677¢	Inverted-Energy
				General Service - Secondary				
19	Limited Commercial Water Heater Rental Service	S	$.02/month/ $1 of investment	None	None			
24	General Service	S	$3.45(B) $13.00(B)	0-50 51-100 101-200 200-Over	None $1.23 1.82 2.46	0-15,000 15001-70,000 70001-Over	2.519¢ 1.709¢ 1.259¢	Inverted-Demand Declining-Energy

28	Commercial Service (Closed)	S	$3.45(B) $13.00(B) $17.50(M)	None	None	0-1500 1501-Over	2.909¢ 1.934¢	Declining-Energy
29	Seasonal Service (Off Peak)	S	$3.45(B) $13.00(B)	0-50 51-Over	None $.85	0-1000 1001-15,000 15,001-Over	1.558¢ 1.199¢ .823¢	Flat-Demand Declining-Energy
			General Service - Primary					
31	Primary General Service	P	$40.00(B) Plus Demand Charge	All	$2.05	0-5000 5001-Over	2.472¢ .864¢	Flat-Demand Declining-Energy
35	Seasonal Primary General Service (Off Peak)	P	$40.00(B) $5.00/HP(M) or $5,000(M)	All	$.80	All	.509¢	Flat-Demand and Energy
39	Optional High Voltage General Service		The Demand Charge	All	$1.47 plus $1.47KW for the highest Critical Demand in previous 12 months	All	.505¢	Flat-Demand and Energy
43	Interruptible Primary for Total-Electric Schools	P	None	All	$.80	All	.99¢	Flat-Demand and Energy

46	High Voltage Interruptible Service	T	$10.85/KW of the maximum billing demand plus .509¢/KWH	None (Demand is Read)	None	0-150KWH Per KW 151-Over KWH Per KW	1.309¢ .509¢	Declining Load Factor Rate - Energy
49	High Voltage General Service	T	$27.50/KW(M)	All	$2.162	All	.505¢	Flat-Demand and Energy

* S - Secondary
P - Primary
T - Transmission

** Rental charge in addition to minimum charge.

Exhibit II-2

Washington Utilities and Transportation Commission

Rate Schedule and Structure Review:

The Washington Water Power Company

Rate Schedule No.	Rate Class Title	Voltage Level*	Minimum (M) or Basic (B) Charge	Demand Charges KW	Demand Charges $/KW	Energy Charges KWH	Energy Charges $/KWH	Rate Structure Classification
1	Residential Service	S	$2.60(B)	None	None	0-1300 1301-Over	1.213¢ 1.413¢	Inverted-Energy
11	General Service	S	$2.60(B) $7.60(B)	0-20KW 21-Over	None $2.00	0-3000 3001-18,000 18,001-Over	1.99¢ 1.65¢ 1.27¢	Flat-Demand Declining-Energy
16	Commercial Water Heating Service	S	$2.60(M)	None	None	All	1.354¢	Flat-Energy
23	Large General Service	S/P	The Demand Charge	0-50 51-Over Primary Service Discount $.10/KW above 11 KV	$100.00 $1.15	0-18,000 18,001-58,000 58,001-Over	1.365¢ 1.115¢ .855¢	Flat-Demand Declining-Energy
25	Extra Large General Service	P	$11,540(M)	None Primary Service Discount $.10/KW above 11 KV	None	0-200Kwh Per KW 201-Over Per KW	1.154¢ .734¢	Declining-Energy

Exhibit II-2
Page 2

32	Pumping Service	S/P	$6.00/KW(M) of the highest demand	None	None	0-85 KWH per KW 2.513¢ 86-160 KWH per KW 1.933¢ Next 12,000 .743¢ All additional .613¢	Declining-Energy

* S - Secondary
P - Primary

Exhibit II-3

Washington Utilities and Transportation Commission

Rate Schedule and Structure Review:

PACIFIC POWER AND LIGHT COMPANY

Rate Schedule No.	Rate Class Title	Voltage Level*	Minimum (M) or Basic (B) Charge	Demand Charges KW	Demand Charges $/KW	Energy Charges KWH	Energy Charges $/KWH	Rate Structure Classification
15	Outdoor Area Lighting Service (dusk to dawn mercury vapor)	S	None	None	Nominal Lumen Rating 7,000 21,000 55,000 plus $1.00/pole for each additional pole in excess of the number of luminaries installed	Rate/Luminaire $ 5.63 9.64 17.87		Flat
16	Residential Service	S	$3.00(B)	None	None	All	1.768¢	Flat-Energy
18	Three Phase Residential Service Rider	S	$3.00(B)	All	$1.55/KW	All	1.768¢	Flat-Demand Flat-Energy
24	General Service	S	$3.00(B) 5.50(B) Plus $1.50/KW In excess of 10 KW	None	None	0-35KWH Per KW 36-70 KW Per KW Next 1400 KWH Next 15000 Next 40000 All additional KWH	4.01¢ 3.72 2.38 1.76 1.36 1.29	Declining-Energy
33	Partial Requirements Service	P/S	$1.25/KW for 100 KW		$1.25/KW Standby Charge	By schedule 36		

36	Large General Service Optional 100 KW and Over	P	Current KW Charge or Average of 3 highest Months	0-100 Over 100 Primary Voltage Discount: 1½% for losses Standard Voltage Discount: .15¢/KW	$150.00 $1.15/KW	0-50 KWH Per KW Next 20,000 Next 50,000 Next 200,000 All additional KWH	 1.95¢ 1.63 1.38 1.17 1.06	Declining-Energy
38	Space and Water Heating for Churches (No new service)		$3.00(M) $5.50(M)	None		All	2.08¢	Flat-Energy
40	Irrigation and Soil Drainage Pumping Service		$17.00/Season or $8.50/KW Highest Demand			Monthly rate 0-50 50-150 KWH per KW 151-250 KWH per KW All additional KWH	 $3.15 3.28¢ 2.08¢ 1.29	Declining-Energy
				<u>Maximum Seasonal Rate</u>				
				All	$11.00/KW	0-400 KWH per KW All additional KWH	 1.99¢ 1.29¢	Flat-Demand Declining-Energy
42	Controlled Water Heating Service (No new service)		$3.00(M) plus $1.50/KW in excess of 10 KW	None		All	1.88¢	Flat-Energy

47	Partial Requirements Service 10,000 KW and Over		Demand Charge plus standby Charge	0-10,000 $15,500 All additional KW $1.25/KW Standby charge: 1.25/KW 60 KV Delivery Discount: .12¢/KW	0-50 KWH per KW 1.919¢ See rate schedule for interpretation1.194 All additonal KWH .869 All KWH in excess of 600 KWH/KW 1.174	Flat-Demand Declining-Energy
48	Large General Service -High Voltage 10,000 KW and Over	P	Demand Charge	0-10,000 $13,500 All additional KW $1.05 60 KV Delivery Discount: .12¢/KW Nonstandard Voltage/increase: .15¢/KW	0-50 KWH Per KW 1.379¢ See rate schedule for interpretation1.294 All additional KWH .944	Flat-Demand Declining-Energy

* S - Secondary
P - Primary

SECTION III

COMPARISON OF EXISTING RATE STRUCTURES AND LEVELS

WITH ESTIMATED EMBEDDED AND MARGINAL COSTS OF SERVICE

INTRODUCTION

The approval of any rate structure and level by the WUTC will have certain resource allocation implications. Before these resource allocation implications can be evaluated, the rates themselves must be compared and contrasted with the utilities' marginal and embedded costs. Such a comparison would form the basis from which any resource misallocations inherent in the existing rate structures and levels can be estimated.

METHODOLOGY

As previously mentioned, the investor owned utilities in the State of Washington have not been required to submit cost of service studies to the WUTC. Consequently, one of the goals of this study is to estimate both the traditional average embedded cost of service (TAECOS) and the marginal cost of service (MCOS) by major customer classes. The scope of this study is limited to an estimation of these costs. Detailed calculations which one might expect to submit in a rate proceeding have not been performed.

Because of the voluminous number of rate schedules for each of the three investor owned utilities in Washington and because of the limited scope of this study, TAECOS and MCOS have been calculated for four major customer class definitions. These customer classes are residential, general service-small, general service-large, and general service-high voltage. These class definitions parallel the traditional customer class and tariff definitions adopted by the three investor owned utilities. The general service-small classification includes all commercial and industrial customers receiving voltage at a secondary level voltage, generally 480 volts or less. The general service-large classification includes all commercial and industrial applications which are serviced at greater than 480 volts, but less than any subtransmission voltage which is generally categorized as 34.5 or 69 KV. The general service-high voltage classification includes all customers that receive service from either the subtransmission or the transmission system. TAECOS and MCOS are estimated for these four customer classifications. As noted earlier, it is beyond the scope of this report to make detailed cost calculations by both utility and tariffs. We believe that a comparison of selected rates for each of the investor owned utilities with single figures representative of the traditional average embedded and marginal costs of service sufficiently represents the individual customer class costs for all three utilities.

These average embedded and marginal cost estimates were developed through application of a proprietory methodology. Inputs to this methodology include: historic plant and expense data from FPC Form 1; projected plant and expense data submitted pursuant to the current WUTC generic electric rate hearings (U-78-05); and detailed calculations of average embedded and marginal costs of other regional utilities. The methodology, accounting for differences among regional utility costs, produces point estimates of the system average embedded and marginal costs for the capacity-, energy- and customer-related costs of service. These cost estimates are calculated for and segregated by customer classes when average embedded cost estimates are produced. The estimates are calculated for and segregated by time differentiated periods and service voltage levels when marginal cost estimates are produced.

Since the TAECOS and MCOS have not been estimated by individual utility tariff, the rate comparisons contained in this section are based on those rates which represent the bulk of the utilities' jurisdictional sales. For example, evaluation of the annual sales statistics for Puget Power indicates that Schedule No. 24 is both representative of a general service-small customer tariff and is also the tariff which provides the bulk of the utility's sales under the general service-small classification. Based on the utility's information filed at the WUTC and Federal Energy Regulatory Commission (FERC) and other assumptions made by the EES staff, comparisons of the existing rate structures and levels with the TAECOS and MCOS have been made.

Reference is made throughout this section to TAECOS and MCOS. Historically, TAECOS has been conducted to allocate the utility's embedded plant and annual operation and maintenance expenses to the individual customer tariffs or customer classes. These allocations have historically been made on the basis of customer consumption characteristics. Also, these allocations have been applied to the utility's accounting records which follow FERC's Uniform System of Accounts. As a result, TAECOS yields calculations of the demand-, energy-, and customer-cost components of supplying service. These records do not recognize any time variant characteristics of costs being allocated to customer classes.

Juxtaposed to this methodology are those which calculate MCOS. In such a series of calculations, the time variant nature of the marginal costs of supplying electric service are explicitly considered. A marginal cost of service study does not require allocation of specific costs to customer classes. Instead, the specific marginal costs of providing electric demand and energy are calculated for any point in time for service to any customer at any location on the system. These costs, along with the customer-component costs, are calculated on the basis of providing service at selected voltage levels. These voltage levels are generally defined as secondary, primary and transmission levels as described previously. A particular customer receiving voltage at a secondary level will incur system marginal costs regardless of whether the customer is included under the residential or commercial tariffs.

EXISTING RATES AND COSTS COMPARISONS

The results of any cost of service study yield the particular costs in terms of the customer-, demand- and energy-cost components of service to the particular tariff or customer class in question. Such cost of service results cannot be compared directly to an existing rate schedule or level because a large number of utility rates are not structured with a separate demand-, energy- and customer-cost component. This is usually true for the residential and general service-small classes. However, large power rate designs which incorporate kilowatthour per kilowatt of demand also fall under this category. Since both types of rate stuctures exist under those chosen as being representative of the customer classes defined and of the bulk of the utility's sales, a different method of comparing rate structure to cost of service is used. This comparison first establishes typical customer monthly consumption, peak demand and time-of-use characteristics for the four classes for which TAECOS and MCOS have been estimated. Using these assumptions of customer characteristics, the monthly average revenues expressed as dollars per kilowatthour are derived for the existing rate schedule, the average-embedded and marginal cost of service estimations.

Exhibit III-1 summarizes the estimates of the customer classes' TAECOS and MCOS. As noted earlier, these estimates do not represent the actual costs of service for any of the three utilities in question. Instead, they represent the aggregation of several TAECOS and MCOS analyses. Such an aggregation is relied upon because of the limited scope of the estimation techniques utilized in this report. This aggregation is further relied upon because of the myriad numbers of results which could be obtained depending upon the particular allocation methodology employed. These cost of service results are considered generally representative of the results obtained from studies of similar utility systems. Included in these aggregations are estimates of the TAECOS and MCOS of the investor owned utilities being examined by this study. These aggregated costs of service are presented by customer class and by cost component. The customer-component represents the fixed charge which would be recovered by a monthly fixed charge to each customer. The energy-component represents those charges which would be recovered from the customer via charges per kilowatthour. Because of the explicitly time variant nature of marginal costs, these energy charges are identified according to the on-peak period and the off-peak period. As noted in Exhibit III-1, the on-peak hours are from 8:00 a.m. to 8:00 p.m. for all weekdays. All other hours are considered as off-peak hours. The demand-component is shown as dollars per non-coincidential-on-peak demand. The on-peak demand hours are identical to those for the energy charges. It should be noted that a simplifying assumption is made for these marginal cost calculations; there is no seasonality in these marginal demand costs. Consideration of seasonality would create a comparison burden not offset by the benefits.

Exhibit III-2 presents the four rate schedules chosen to be most representative of the customer classes analyzed. As previously discussed, the selection of these tariffs has been based on two criteria. The first criterion is the selection of a rate which, by each utility's definition, represents one of the four customer classes for which costs of service have been estimated. The second criterion is to select, within each of these four customer classes, the rate which represented the greatest quantity of utility sales.

Exhibit III-3 presents those customer consumption characteristics which are used to generate the rate comparison data. There are three important customer consumption characteristics which need to be identified. The first is to the total monthly kilowatthour consumption. The second is the customer's peak demand. (In lieu of the customer's peak demand, assumptions have been made about the customer monthly load factor. Application of this load factor to the monthly consumption yields an estimate of the customer's monthly on-peak demand.) The third customer characteristic deals with the diurnal consumption patterns. This assumption addresses what percentage of the customer's kilowatthour consumption is during the on-peak and off-peak hours.

Exhibit III-4 presents the actual comparisons of the existing rates with the estimated TAECOS and MCOS analysis.[1] These results are expressed in terms of the average revenues generated per kilowatthour. Review of these results leads to the following conclusion: In all cases, the average revenues generated by the existing rates are several multiples less than the average revenues which would be generated by a marginal cost of service rate. This is not an atypical result. Numerous comparisons of revenues generated by existing rates and those revenues generated by marginal cost based rates for utilities throughout the United States have produced similar results. If marginal cost based rates were implemented, the over-recovery of revenues presents a problem for efficient resource allocation in a utility under revenue requirement constraints. This dilemma is discussed more fully in a following section.

Comparison of the revenues generated by the existing rates to those generated by TAECOS based rates yields consistent results among the three investor owned utilities. The revenues generated by the existing rates fall short of the TAECOS findings for the residential sector. Consequently, the system revenue requirements must be recovered from other customer classes. Exhibit III-4 demonstrates that this revenue recovery is accomplished from the three remaining classifications. It is typical to find the greatest rate divergence from average-embedded costs of service within the general service-small classification. The next greatest divergence is generally within the general service-large categorization. Experience has shown that the general service-high voltage classification of customers usually recovers its average-embedded costs of service.

A different manner of looking at the comparisons of the existing rates under TAECOS and MCOS can be found on Exhibit III-5. This table presents the comparisons shown in Exhibit III-4 as ratios. The revenues generatd by the existing rates are expressed as ratios of both the revenues generated by TAECOS and MCOS. These ratios are shown for the four customer classes analyzed in this study. A ratio greater than one indicates that the rate structure does not generate sufficient revenues to cover the estimated costs of service. Likewise, a ratio less than one indicates that the rate structure recovers revenues exceeding the estimated costs of service. An examination of Exhibit III-5 shows the degree to which the existing rates diverge from the average-embedded or marginal costs of service.

Exhibits III-4 and III-5 suggest some rate discontinuities regarding the Washington Water Power Company. Based on a brief analysis, it is our opinion that these disparities are the result of the potential (since only using estimates) need for rate relief on the part of Washington Water Power. The comparisons shown in Exhibits III-4 and III-5 have been evaluated upon the basis of rates in existence in April 1979. They reflect the late March rate increase allowed to Puget Sound Power and Light. EES believes that rate relief for the Washington Water Power Company would remove the disparities which are otherwise observed in Exhibits III-4 and III-5. For example, Exhibit III-4 suggests that none of the four WWP rate classifications recover their average-embedded costs of service. After adequate rate relief, the comparisons exhibited by Puget Power and PPL should be similar to those of WWP.

Several concluding remarks are in order. They are:

1. In all cases, the existing rate structures are significantly divergent from the marginal costs of service;

2. Consistent among the three investor owned utilities in Washington, the existing rate structures for the residential sector are less than the TAECOS;

3. For the remaining three customer classes, the existing rates are greater than the TAECOS;

4. For the residential sector, the TAECOS tends to be 30% to 100% greater than rates in use;

5. In the remaining rate structures, the existing rates are 6% to 24% greater than TAECOS;

6. The resource allocation efficiency derived from the divergence of the existing rates from both TAECOS and MCOS will be reviewed in a following section.

SECTION III FOOTNOTE PAGE

[1] Caution must be exercised when interpreting these rates to costs comparisons. As noted earlier, these costs data are estimates of the representative average-embedded and marginal costs of service by class for regional investor owned utilities. The costs data are <u>not</u> actual costs calculations for each utility reviewed. Proximity estimates were made for class costs and assumed representative for all utilities. These proximity estimates are unequal, except by coincidence, to the actual class costs that could result from detailed utility specific calculations. Such detailed utility specific calculations, which one might expect to be submitted during a rate increase application proceeding, were beyond the scope of this study. Consequently, these comparison tables represent only direction and level of rates to costs differences, but do not represent precise differences or multiples.

Furthermore, one goal of this study was to compare the current rates with actual marginal costs expressed as rates. Revisions of marginal costs to reflect each of the utilities' revenue requirements were beyond the scope of this study. However, experience would suggest that even if marginal cost rates adjusted to revenue requirements in appropriate time periods were considered there would be no significant difference in the comparison of expected consumer response.

EXHIBIT III-1

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

COST OF SERVICE SELECTION

Class	Cost Type	Demand[1] ($ per Noncoincidental on-peak KW demand)	Energy[2] (cents per KWH-- on-peak/off-peak)	Customer ($ per Customer per month)
Residential	TAECOS	3.00	0.65	6.00
	MCOS	10.00	3.5/0.7	16.00
General Service - Small	TAECOS	3.00	0.65	18.00
	MCOS	10.00	3.5/0.7	20.00
General Service - Large	TAECOS	2.50	0.60	45.00
	MCOS	9.00	3.3/0.7	50.00
General Service - High Voltage	TAECOS	2.50	0.60	60.00
	MCOS	8.00	3.0/0.6	100.00

On-peak hours are all weekdays from 8 a.m. to 8 p.m.
All other hours are off-peak

[1] For the marginal costs, seasonality of costs are not considered
[2] Adjusted to reflect losses

TAECOS refers to Traditional Average Embedded Costs of Service
MCOS refers to Marginal Costs of Service unadjusted to revenue requirements

EXHIBIT III-2

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

UTILITIES' TARIFFS SELECTION

UTILITY AND TARIFF NUMBER

Class	Puget Sound Power and Light	Pacific Power and Light	Washington Water Power
Residential	7	16	1
General Service - Small	24	24	11
General Service - Large	31	36	23
General Service - High Voltage	49	48	25

EXHIBIT III-3

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

CUSTOMER CLASS CHARACTERISTICS ASSUMED

Class	Monthly Consumption (KWH)	Monthly Load Factor (%)	Diurnal KWH Consumption Pattern	
			% On-Peak	% Off-Peak
Residential	1,000	25	65	35
	3,000	20	45	55
General Service - Small	3,000	30	90	10
	20,000	35	70	30
General Service - Large	200,000	45	55	45
General Service- High Voltage	10,000,000	95	35	65

EXHIBIT III-4

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

COMPARISON OF RATES WITH COSTS OF SERVICE

AVERAGE REVENUE PER KILOWATTHOUR

RESIDENTIAL CLASS

	Puget Sound Power and Light		Pacific Power and Light		Washington Water Power	
	1,000 KWH	3,000 KWH	1,000 KWH	3,000 KWH	1,000 KWH	3,000 KWH
	Cents Per KWH					
Actual Rate	2.12	1.99	2.07	1.87	1.47	1.41
TAECOS	2.75	2.85	2.75	2.85	2.75	2.85
MCOS	9.12	9.16	9.12	9.16	9.12	9.16

GENERAL SERVICE-SMALL CLASS

	3,000 KWH	20,000 KWH	3,000 KWH	20,000 KWH	3,000 KWH	20,000 KWH
	Cents Per KWH					
Actual Rate	2.93	2.77	2.89	2.37	2.09	1.69
TAECOS	2.75	1.86	2.75	1.86	2.75	1.86
MCOS	8.87	6.51	8.87	6.51	8.87	6.51

GENERAL SERVICE-LARGE CLASS

	Cents Per KWH		
Actual Rate	1.83	1.69	1.32
TAECOS	1.42	1.42	1.42
MCOS	4.96	4.96	4.96

GENERAL SERVICE-HIGH VOLTAGE CLASS

	Cents Per KWH		
Actual Rate	1.11	1.26	0.85
TAECOS	0.95	0.95	0.95
MCOS	2.80	2.80	2.80

TAECOS refers to Traditional Average Embedded Costs of Service
MCOS refers to Marginal Costs of Service

EXHIBIT III-5

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

RATIOS OF COSTS OF SERVICE TO RATES

RESIDENTIAL CLASS

Cost: to Actual Rate	Puget Sound Power and Light		Pacific Power and Light		Washington Water Power	
	1,000 KWH	3,000 KWH	1,000 KWH	3,000 KWH	1,000 KWH	3,000 KWH
TAECOS	1.29	1.44	1.33	1.53	1.87	2.02
MCOS	4.29	4.60	4.41	4.90	6.19	6.48

GENERAL SERVICE-SMALL CLASS

	3,000 KWH	20,000 KWH	3,000 KWH	20,000 KWH	3,000 KWH	20,000 KWH
TAECOS	0.94	0.67	0.95	0.79	1.32	1.10
MCOS	3.03	2.37	3.07	2.75	4.24	3.85

GENERAL SERVICE-LARGE CLASS

TAECOS	0.78	0.84	1.08
MCOS	2.71	2.94	3.76

GENERAL SERVICE-HIGH VOLTAGE CLASS

TAECOS	0.86	0.76	1.12
MCOS	2.54	2.23	3.30

A ratio less than 1.00 indicates that the actual rate recovers revenues in excess of the cost.

A ratio greater than 1.00 indicates that the actual rate fails to generate revenues sufficient to cover the costs.

TAECOS refers to Traditional Average Embedded Costs of Service
MCOS refers to Marginal Costs of Service

SECTION IV

THE IMPACT OF ALTERNATE RATE STRUCTURES ON ELECTRICAL CONSUMPTION

INTRODUCTION

When examining the impact of rates upon electricity consumption, an important distinction between rate levels and rate structures must be made. This distinction is necessary because of the propensity towards demand, customer and energy charges in the design of electrical rates. A reasonable definition of rate level is the average costs per kilowatthour derived from a rate tariff. It is of interest to examine not only the impact upon consumption of varying this absolute level, but also the impact of charging the same average price through different configurations of demand, customer and energy charges. The latter is a question of rate structures. In order to evaluate the effect of alternate rate structures and rate levels upon the level of electricity consumed, an analytical structure has been developed. The analytical structure emphasizes three important points. They are:

1. Evaluating the impact of alternate rate structures upon electrical consumption is a distinctly different problem than the one of forecasting the absolute level of future electricity demands.

2. Because the goal of the analysis is to isolate price effects upon consumption, it is necessary to examine econometric estimates of price elasticity.

3. *A priori*, it can be expected that the response of consumers to electricity prices will vary significantly among customer classes and probably even within each class. Accordingly, a survey of the current econometric literature dealing with price elasticity estimates of the residential, commercial and industrial customer classes has been undertaken. The goal of this survey is to define the reasonable consumption impact ranges of prices upon the alternate rate structures examined in this report. This analysis demonstrates that current research has addressed some rate impact questions but many questions are still unanswered, especially those dealing with the impacts of time of use rate and regional variations in price responses.

ANALYTICAL FRAMEWORK

Electricity is an input factor to both consumption and production. Electricity can generally be characterized as an intermediate good which is consumed rarely, if ever, as a final product. Thus, the demand for electricity is derived from the demand for the final goods and services it goes into producing. This simple observation yields two important implications. First, it can be expected that the consumption response to electricity rates will vary among its end uses. Distinct end uses will have different growth patterns and technologies. This suggests variability in both the energy intensities and the technical abilities to substitute other inputs for electricity. At the minimum, an analysis of rate structure impacts upon consumption should distinguish between residential and commercial consumers, who would generally purchase electricity to produce final consumption services, and industrial consumers, who will employ electricity in their production processes. Secondly, because most electricity is used in conjunction with a durable stock of electricity using devices, it can be expected that consumption pattern changes will take a period of time to be fully realized. In the short run, the durable stock is fixed and only appliance utilization rates can change. For this reason, consumers are limited in the ways which they can respond to changing prices. In the long run, however, the durable stock is not fixed and consumers have a greater degree of flexibility in their reactions. Thus, the magnitude of consumer responses will vary significantly across periods of time. An adequate analysis of electricity consumption must explicitly take these time distinctions into account. To summarize, the consumption response to electricity prices can be expected to have at least two dimensions. These dimensions are: 1) by time; and 2) by end use. These will vary at least among customer classes and probably within each class.

It should be emphasized that the question of the impact of alternate rate structures upon electrical consumption is distinctly different from the question of what future electrical loads will be. Other factors, such as income, population, industrial output levels and prices of all energy sources, affect the demand for electricity. The assertion that higher electrical rates will tend to decrease electrical consumption does not imply that the absolute level of that consumption will fall. It is only a comparative path analysis. It should be interpreted as saying that, given a fixed level of other causal variables, higher electrical prices will cause a lower consumption level than would have existed had those prices remained stable. Changes in other causal variables, such as income or population, can cause the absolute level of consumption to increase.

It should be clear that in order to address the question at hand, techniques must be examined which isolate the impact of prices from the impact of other causal variables. In general, this implies econometric price elasticity estimates. It should be emphasized that econometric approaches are essentially estimation models which explain the relationship between energy consumption and rate structures, among other factors. These models are developed with reference to the economic theories of the firm and the consumer. In addition, it is typical for the statistical estimation of these models to be carried out through some form of least squares analysis. These two observations have several important practical implications. First, the price elasticity estimates are just that; sample estimates of the true value of the parameter. While it is typical to report these estimates as single point expected values, they are properly thought of as ranges, not points. For instance, if one study reports the price elasticity of electrical consumption for the commercial customer class to be -.6 and the same elasticity for the residential class to be -.5, it should not be concluded that the elasticity of the residential class is necessarily greater than the price elasticity for the commercial class. While these estimates are <u>numerically</u> different, they may not be <u>statistically</u> different.

Secondly, the economic theory of the consumer derives generalized demand functions which argue that consumers demand for goods (in this case the end use services that the consumer obtains from electricity) depend upon the consumers ability to pay for goods, his income, and the price of all other goods in the economy. The economic theory of the firm argues that a firm's demand for an input (in this case electricity) depends upon the price it receives for its product and the price of all relevant inputs into production. Econometric models can be viewed as an attempt to quantify these relationships. Obviously, in their general form, these relationships are quite extensive and econometric simplification is common. To illustrate, many econometric models attempt to estimate consumers' demand for electricity by including only the price of electricity and the price of natural gas. It is possible that during this simplification process important explanatory variables have been excluded. If this is the case, then some of the impact on electrical consumption associated to the price by these studies may in fact be derived from other unestimated variables. These are errors of specification. Also, it should be noted that there is a possibility of obtaining a regression equation relating economic variables with an apparently high degree of fit (i.e., conventional test procedures are satisfied) when in fact the independent variables have no explanatory power whatsoever. This discussion re-emphasizes the need for considering econometric estimates as reasonable ranges. It also points out that extreme care must be taken when applying econometric estimates based on national data to regional policy considerations. Finally, statistical estimates are only as good as the data from which they are constructed. There is a general dearth of data relating electrical consumption to electricity prices.

Most econometric studies relate electrical consumption to average price. Thus, these studies address questions of rate levels. There is very little data (and thus very few studies) relating electrical consumption to rate structures. This is particularly true in connection with time of use rates.

RESIDENTIAL PRICE ELASTICITY ESTIMATES

Exhibit IV-1 presents a survey of econometric estimations of price and income elasticities for residential electricity demand. Note that the table presents both short and long run price elasticity estimates, the type of price variable employed in the estimation and characteristics of the data base from which the estimations were derived. There are three types of prices reflected in the table. These are: average, marginal and intermarginal. First, it should be noted that all of the price variables are expressed in real terms. By this, it is meant that the variables are deflated by some index of other prices in the economy. Thus the elasticity should be interpreted as the estimated percentage change in consumption that would result if the price of electricity increased at a greater rate than other prices within the index. The studies predict no change in electricity consumption if the price of electricity increases at the same pace as the index. The presence of three types of price variables is reflective of the difficulties which arise because of the propensity to charge electricity under block structures. In general the average price variable is computed by dividing the total revenues generated from the residential class by the total kilowatt hour consumption of that class. The marginal price is computed by taking the block rate in which the average consumption falls. The marginal price thus reflects the average cost of purchasing an additional unit of consumption. The intramarginal price is estimated by subtracting the revenues which would have been generated had only the marginal price been charged from the revenues which were generated under the actual block structure. The rationale here is to derive a measure which reflects the level of customer service charges and the level of rate on the nonmarginal blocks. The implications of each of these price variables are discussed in detail below.

The short and long run elasticities should be interpreted in the following manner. The short run elasticities are the impact upon electrical consumption that changes in prices or income would have this year. For instance, the Houthakker-Taylor Study estimates the short run price elasticity of residential electric energy consumption to be -0.13. This implies that the impact this year of a 1% increase in the real average price of electricity would be a decrease of 0.13% in residential electric energy demand. The long run price and income elasticities should be interpreted as the cumulative impacts of a change this year in either price or income upon electrical consumption over a long period of time. How long is long? This varies from study to study, but a 20 year period is a reasonable rule of thumb. Note that the Houthakker-Taylor Study estimates the long run price of elasticity of residential consumption to be -1.89. This should be read as asserting that the same 1% increase in the real average price of electricity which only resulted in a decrease in energy consumption of 0.13 per cent this year would cumulatively result in a decline of energy consumption of 1.89% over a long period of time (say 20 years). The data bases from which these studies are drawn consists of both time series and cross sectional data. Time series denotes data collected for the same variables through time, whereas cross-sectional denotes data collected by variables across cross sectional units such as states or cities. The important point to note here is that most of the studies draw upon data which are national in scope. Case must be taken in applying these elasticity estimates on a regional basis because regional differences in the patterns of electricity consumption can be expected. The response of consumers to price changes in an area utilizing electricity primarily for space heating could be expected to vary significantly from the price responses in an area utilizing primarily natural gas for space heating. But, reiterating, these elasticity estimates are properly thought of as ranges, not points. Examination of the survey reveals that the elasticity estimates, though obtained from a great variety of different data bases, are reasonably clustered. They should provide likely ranges for residential price responses in Washington.

THE IMPACT OF ALTERNATE RATE STRUCTURES UPON RESIDENTIAL CONSUMPTION

The question now becomes what the econometric literature tells us about the probable impact of alternate rate structures upon residential consumption. First, note that the majority of studies deal only with the impact of the average price of electricity upon demand. These studies can address only the question of the impact of rate level and not the question of the impact of rate structure. Examining only these studies, we find that the short run price elasticities vary from a low of -1.00 to a high of -.13. The long run price elasticity estimates vary from a high of -.189 to a low of -1.21. Combining these results with the projected average cost per kilowatthour of alternate rate structures derived in Exhibit III-4 and III-5, it is possible to obtain estimates of the impact of alternate rate levels upon residential electric consumption. To illustrate, from Exhibit III-5 it is obtained that for PP&L residential customers in the 3,000 KWH range the implementation of rates based on marginal cost of service would result in an increase in the average price per KWH of 390%. Multiplying this by the short run price elasticity range (-.13 - -1.00) the estimated impact of the implementation of rates based on marginal cost of service to these residential consumers would be an immediate decrease in electrical consumption ranging from 51% to 390%. Repeating the exercise for the long run price elasticities, the estimated cumulative decrease in consumption over many years would range from 351% to 738%. Exhibit IV-2 presents a complete tabulation of the expected impact upon residential consumption resulting from the implementation of the alternate rate levels presented in Exhibit III-4.

To this point the analysis has addressed only the question of the impact of alternate rate levels upon residential consumption. The question now becomes what is the effect of charging the same average kilowatthour price for different rate structures. There are many methods in which electrical rate structures are altered. Time of use rates, flat rates, inverted rates and declining block rates are examples. The latter three rates structures can essentially be viewed as different configurations of customer service charges and rate blocks. Since these are the most likely rate structure adjustments for the residential class, the question of their impact upon residential consumption will be addressed first. Econometric studies have addressed the question of residential rate structure by disaggregating the price of electricity into two components. The first component, known as the marginal price, is the price that the consumer must pay if he increases or decreases his consumption slightly. Obviously, this price is determined by the block charge in which the customer's consumption falls.[1] But this is not the only price that is important to the consumer. Changes in customer service charges or in the rate on blocks above the marginal block also affect consumption. These charges are termed intermarginal prices in econometric literature. Examination of Exhibit IV-1, which displays econometric estimates of price and income elasticities for residential demand, shows that only two studies separately estimated the impact of both marginal and intermarginal prices. Both of these studies estimated a slightly more sensitive response of consumption to marginal prices. This would indicate that some decreasing consumption might result from inverted or flat rate structures which would probably increase prices at the marginal consumption block at a greater rate than they would decrease customer and interior block charges. But note that most of the econometric estimates of income elasticity fall within the same range as the estimates of price elasticities. <u>There are strong theoretical reasons to believe that consumers will response to changes in intermarginal charges in the same manner as they respond to changes in income.</u>[2] This would indicate that alternate rate structures which offset increases in marginal prices by decreases in customer service and interim marginal block charges would have minimal, if any, impact on consumtion. Thus the evidence of the impact of alternate rate structures upon residential consumption is inconclusive.

Similarly, quantitative evidence about the impact of time of use residential rates upon consumption is almost nonexistent. This is to be expected because of the limited application of these types of rates. It is also to be expected because of prohibitive metering costs. In fact, in 1972 British utilities decided that the mandatory time of use kilowatthour rates were not cost effective. The first time of use tariff applicable to our residential customers in the United States was established in January 1976 by the Central Vermont Public Service Board. The tariff was optional. The first mandatory time of use rates were offered by Long Island Lighting in 1978, and will be offered by the Dayton Power and Light Company and the Virginia Electric Power Company in 1979. For a historical summary of the implementation and impacts of residential time of use rates, see: California Load Management Research 1977, California ERCDC, Cooperative Agreement No. CA-04-60641-00, October 1977. In general, residential time of use rates can be expected to induce some load shifting. The exact magnitude of that shift is unknown.

COMMERCIAL PRICE ELASTICITY ESTIMATES

Exhibit IV-3 presents a survey of econometric estimations of price elasticities for commercial electricity demand. This table is indicative of the state of the art in commercial load research. There has simply not been extensive analysis performed. Several observations should be emphasized from these studies. As with the residential studies, most of the commercial studies deal only with the impact of rate levels (i.e. the price variable is an average price). The study which distinguished between short and long run elasticities found significant differences in the response to a price change through time. Again, this was also true of the residential studies. Thirdly, the commercial price elasticity estimates are very similar in magnitude to those obtained for the residential class.

THE IMPACT OF ALTERNATE RATE STRUCTURES UPON COMMERCIAL ELECTRICITY CONSUMPTION

Exhibit IV-4 presents projected percentage changes in commercial consumption resulting from the implementation of the rate levels given in Exhibit III-4. The computational methodology was identical to the one applied to obtain these estimates for the residential class.

As was the case in the residential studies, these econometric estimations provide little information about the impact of alternate rate structures as opposed to the impact of alternate rate levels. In fact, only the study by McFadden even attempts to address the question of the impact of rate structure. All of the other studies have employed average price as their dependent variable. This is an extreme disappointment because it is typical to apply not only block charges, but demand charges as well, to commercial classes. The impact of altering demand charges upon commercial consumption is almost unknown. Note that the study by McFadden estimated the impact of the ratio between marginal and average price. This study estimated a slight negative impact to this ratio. This implies that there might be a decrease in consumption resulting from inverted rate or flat rate structures which increase the ratio of marginal price to the average. But as McFadden admits, there are some difficulties with the specification of his study and the evidence should not be regarded as conclusive.[3]

The impact of time of use rates upon commercial consumption is also difficult to ascertain. Almost no quantitative estimates of the impact of these rates exist. In January of 1977, Pacific Gas and Electric Company of California implemented time of use rates for all customers whose monthly billing demand exceeded 4000 KW. Exhibit IV-5 presents a delineation of that rate, along with a description of the customers to which the rate would apply. The major difference in the rate between on-peak periods and off-peak periods was the demand charge. Exhibit IV-6 and IV-7 present a comparison of load curves before and after the implementation of the A-17 rate. One interesting qualitative observation is that large commercial consumers (i.e. the hospital, the nonresidential building and the university) responded to the time of use rate not by altering load consumption patterns, but by simply reducing overall consumption. Another observation is that the customers' responses to a time of use rate differ dramatically within the same customer classification as demonstrated by the nonresidential building load curves. In conclusion, this qualitative analysis indicates that large commercial consumption is probably responsive to time of use rates. Furthermore, there is some evidence that this response will take the form of reduced consumption and not shifting in load patterns. The quantitative nature of this response, whether it is regionally specific or whether it differs significantly between different types of commercial users, is unknown.

INDUSTRIAL PRICE ELASTICITY ESTIMATES

Exhibit IV-8 presents a survey of econometric estimations of price elasticities for industrial electricity demand by selected standard industrial codes. All the elasticity estimates are long run and deal only with the impact of average prices. Note that there are significant variations in the estimations between industries. Finally, the range of elasticity responses is not significantly different from those obtained for the commercial or residential classes.

THE IMPACT OF ALTERNATE RATE STRUCTURES UPON INDUSTRIAL ELECTRICITY CONSUMPTION

Exhibit IV-9 presents projected percentage changes in industrial consumption resulting from the implementation of the rate levels given in Exhibit III-4. The computational methodology was identical to the one applied to obtain these estimates for the residential and commercial classes.

The authors know of no econometric estimates of industrial price elasticities which deal with the impact of prices other than average price. Thus the question of impact of alternate rate structures upon industrial demand cannot be addressed. This is particularly unfortunate for the question of the impact upon consumption of such things as demand charges, interruptible rates, etc., is of critical interest.

The PG&E experience gives some qualitative evidence about the impact of time of use rates upon industrial consumption. Examine Exhibit IV-6. Clearly, there is evidence that industrial consumers respond to time of use rates through alteration of their load consumption patterns. Note that this is in contrast to the responses that PG&E obtained from large commercial customers. Exhibit IV-10 computes percentage changes in on-peak KW and KWH consumption for the four industries represented in Exhibit IV-6. Note that there are significant differences in the responses across the industries.

As with the commercial data, this analysis should be viewed as preliminary. No quantification or regional analysis has been done. In fact, there is no way of discerning what changes occur <u>because</u> of the time of use rates.

CONCLUSIONS

This section has surveyed the econometric literature estimating price elasticities for the residential, commercial and industrial classes. It has attempted to address the question of the impact of alternate rate levels and rate structures upon electricity consumption. Serveral conclusions can be drawn:

1. Extensive evidence exists that the level of electrical rates has significant negative impact upon the consumption of all classes.

2. The magnitude of price responses is probably very similar among all customer classes.

3. The magnitude of the price responses is probably much greater in the long run than in the short run. It is almost certainly inelastic in the short run and may even be inelastic in the long run.

4. There is evidence that the response of industrial consumers to prices varies significantly across industries.

5. The evidence regarding the impact of alterations in rate structure, through such devices as inverted or flat rates, upon consumption is inconclusive.

6. There is no quantitative evidence how commercial and industrial consumers respond to time of use rates. Current research does however suggest that the response varies across industries and probably within industries. There is also evidence suggesting a significant variation in the response of industrial and commercial customers.

SECTION IV FOOTNOTE PAGE

1 Unless the consumption changes alters the applicable block.

2 See Taylor (1977).

3 See McFadden (1977), page 11.

EXHIBIT IV-1

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ECONOMETRIC ESTIMATIONS OF PRICE AND INCOME ELASTICITIES OF RESIDENTIAL ELECTRICITY DEMAND

Source[c]	Type of Price[b]	Price Elasticity Short-run	Price Elasticity Long-run	Income Elasticity Short-run	Income Elasticity Long-run	Type of Data
Fisher-Kaysen (1962)	A	-0.16 to -1.00	N.A.	-0.15 to 0.89	-0.18 to -0.78	TS: By state
Houthakker-Taylor (1970)	A	-0.13	-1.89	0.13	1.93	TS: Annual aggregate U. S.
Wilson (1971)	A	N. A.	-1.33	N. A.	-0.46	TS: Cities
Mount, et al. (1973)	A	-0.14	-1.21	0.03	0.03	CS-TS: States
Anderson (1973)	M	N. A.	-.091[a]	N. A.	1.13	CS: States
Lyman (1973)	A	N. A.	-0.90	N. A.	-0.20	CS-TS: Utilities
Acton, et al. (1975)	M	N. A.	-0.70	N. A.	0.40	CS: Small geographic areas
	M	(-0.34)		(0.41)		CS: Small geographic areas
Taylor, et al. (1975)	M	-0.97	-0.78	0.10	1.18	TS: States
Lacy-Street (1975)	M	(-0.45)		(1.87)		TS: One utility are

EXHIBIT IV-1 Cont.

Wilder-Willeborg (1975)	A	-1.00	-1.31	0.16	0.34	CS: Individual households
Uri (1975)	A	-0.61	-1.66	0.04	0.12	TS; Monthly aggregate U. S.
FEA (1976)	A	-0.19	-1.46	0.30	1.10	CS-TS: Census regions
Halvorsen (1976)	M	N. A.	-0.97	N. A.	0.70	CS: States
McFadden-Puig (1975)	A&M	N. A.	-0.22 to -0.71	N. A.	0.99	CS: States
Taylor (1977)	M	-0.07	-0.81	0.09	1.05	CS-TS: States
Taylor (1977)	I	-0.01	-0.14	0.09	1.05	CS-TS: States
Russell (1978)	M	-0.09	-0.41	0.24	1.11	TS-CS: Utility Service Area
Russell (1978)	I	-0.06	-0.26	0.24	1.11	TS-CS: Utility Service Area

a. With appliance saturations fixed, a price elasticity of -0.63 was obtained.

b. A = average price; M = marginal price; I = Intermarginal

c. This is drawn in part from McFadden (1977).

EXHIBIT IV-2

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

PROJECTED PERCENTAGE CHANGES IN RESIDENTIAL CONSUMPTION RESULTING FROM IMPLEMENTATION OF RATE LEVELS GIVEN IN EXHIBIT III-4

	1000 KWH				3000 KWH			
	Short-Run (Immediate Impact)		Long-Run (Cumulative Impact)		Short-Run (Immediate Impact)		Long-Run (Cumulative Impact)	
	From	To	From	To	From	To	From	To
Puget Sound Power and Light								
Actual Rates	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TAECOS	-3.83	-29.45	-26.51	-55.66	-5.61	-43.14	-38.83	-81.54
MCOS	-42.81	-329.30	-296.37	-622.37	-46.81	-360.07	-324.06	-680.53
Pacific Power and Light								
Actual Rates	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TAECOS	-4.29	-32.98	-29.68	-62.33	-6.14	-47.22	-42.49	-89.24
MCOS	-44.33	-341.01	-306.91	-644.50	-50.75	-390.36	-351.33	-737.76
Washington Water Power								
Actual Rates	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TAECOS	-11.27	-86.69	-78.02	-113.85	-13.22	-101.70	-91.53	-192.91
MCOS	-67.49	-519.14	-467.23	-981.19	-71.27	-548.27	-493.44	-1036.22

NOTES:

1. See Text for Computational Methodology.
2. This is a Ceterius paribus analysis.
3. TAECOS refers to Traditional Average Embedded Cost of Service.
   MCOS refers to Marginal Cost of Service.

EXHIBIT IV-3

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ECONOMETRIC ESTIMATIONS OF PRICE ELASTICITIES
FOR COMMERCIAL ELECTRICITY DEMAND

Source	Type of Price	Price Elasticity Short-Run	Long-Run	Type of Data
Mount, et al (1973)	A	-.20	-1.60	CS-TS: States
Halvorsen (1976)	A	N. A.	- .92	CS: States
McFadden (1972)	A	N. A.	- .73	CS: States
McFadden (1972)	M/A	N. A.	- .55	CS: States

Where:

A = Average Price
M = Marginal Price
CS = Cross-sectional
TS = Time Series

EXHIBIT IV-4

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

PROJECTED PERCENTAGE CHANGES IN COMMERCIAL CONSUMPTION (G. S. SMALL)
RESULTING FROM IMPLEMENTATION OF RATE LEVELS GIVEN IN EXHIBIT III-4

	3000 KWH			20,000 KWH		
	Short-Run *	Long-Run		Short-Run *	Long-Run	
		From	To		From	To
Puget Sound Power and Light						
Current Rate	0.0	0.0	0.0	0.0	0.0	0.0
TAECOS	+1.3	+3.3	+9.6	+6.5	+18.0	+52.2
MCOS	-40.5	-111.5	-324.4	-27.0	-74.0	-216.2
Pacific Power and Light						
Current Rate	0.0	0.0	0.0	0.0	0.0	0.0
TAECOS	+.9	+2.6	+7.5	4.3	+11.7	+34.1
MCOS	-41.7	-114.0	-331.6	-34.9	-96.0	-279.3
Washington Water Power						
Current Rate	0.0	0.0	0.0	0.0	0.0	0.0
TAECOS	-6.3	-17.3	-50.4	-2.1	-5.7	-16.6
MCOS	-64.3	-178.2	-518.5	-57.0	-156.9	-456.3

NOTES:

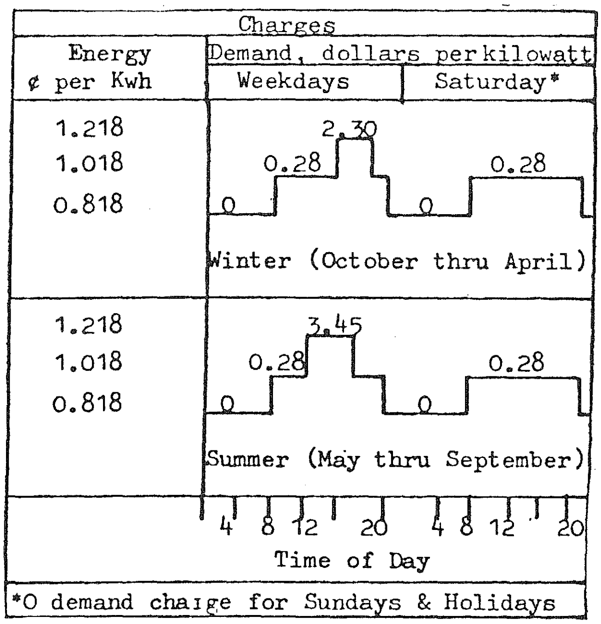
1. See Text for Computational Methodology.
2. This is a ceterius paribus analysis.
3. TAECOS refers to Traditional Average Embedded Cost of Service.
   MCOS refers to Marginal Cost of Service.

* Only one short-run elasticity estimate available.

EXHIBIT IV-5

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

TIME DIFFERENTIATED DEMAND CHARGES



STANDARD INDUSTRIAL CLASSIFICATION		
Customers	Code No.	Industry Group
1	01-09	Agriculture, Forestry, Fishing
8	10-14	Mining
3	15-17	Construction
6	20	Food
10	24	Lumber and Wood
7	26	Paper
8	28	Chemicals
17	29	Petroleum Refining
2	30	Rubber
12	32	Stone, Clay, Glass, Concrete
8	33	Primary Metal Industries
4	35	Machinery, except Electrical
4	36	Electrical Machinery
4	37	Transportation Equipment
7	40	Transportation, Communications, etc.
7	60-67	Finance, Insurance, Real Estate
13	80-89	Services
5	91-97	Public Administration
126 Total		

GEOGRAPHICAL DISTRIBUTION	
Customers	PG&E Division
34	East Bay
16	San Francisco
4	North Bay
4	Sacramento
20	San Jose
1	De Sabla
1	Colgate
5	Shasta
2	Drum
7	Stockton
8	Coast Valley
3	Humboldt
21	San Joaquin
126 Total	

EXHIBIT IV-6

WASHINGTON UTILITIES AND TRANSPORTATON COMMISSION

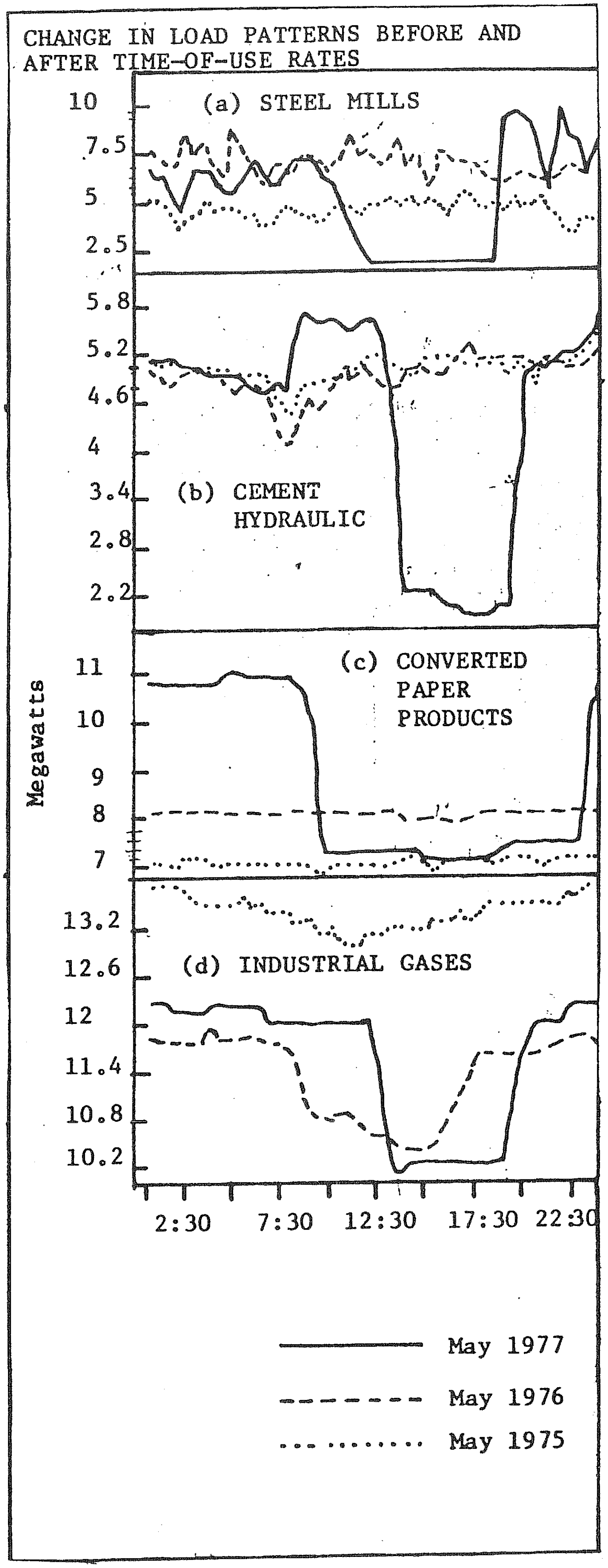
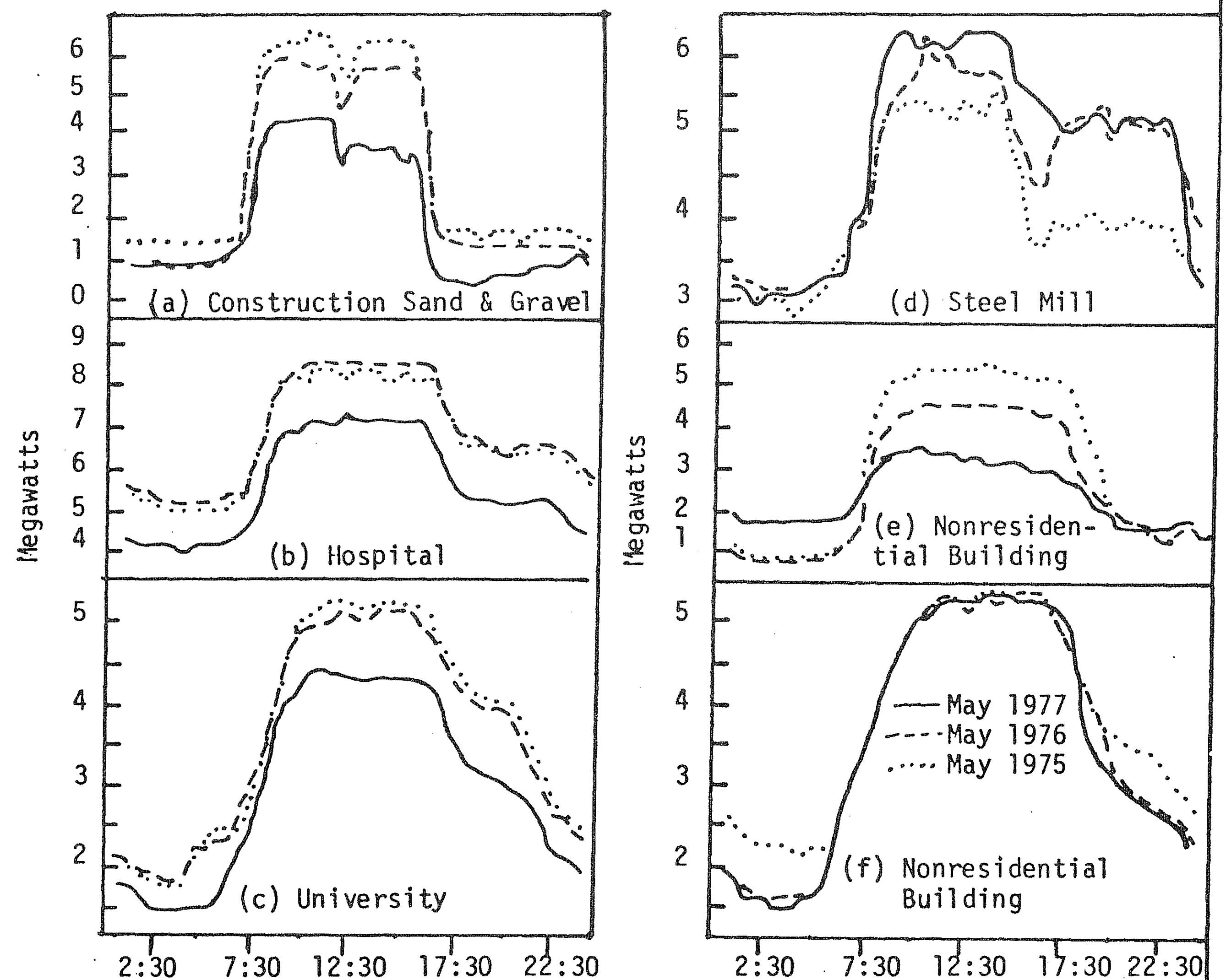
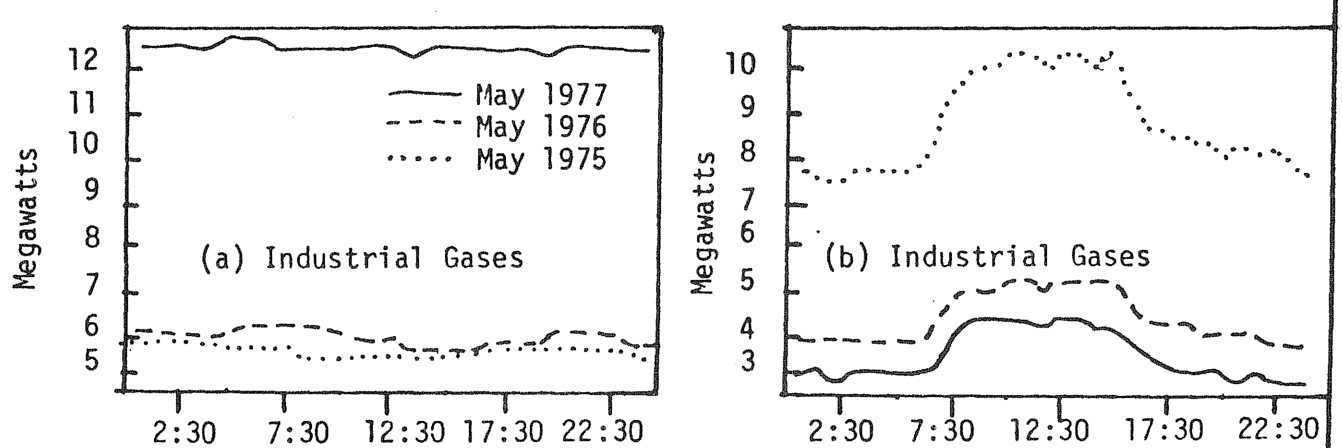


EXHIBIT IV-7 WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

CHANGE IN LOAD PATTERNS BEFORE AND AFTER TIME-OF-USE RATES



LOAD PATTERN DIFFERENCES IN IDENTICAL SIC CODE INDUSTRIES



NOTE: b), c), e), and f) are commercial customers. All others are industrial customers.

EXHIBIT IV-8

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ECONOMETRIC ESTIMATIONS OF PRICE ELASTICITIES FOR INDUSTRIAL ELECTRICITY DEMAND

BY SELECTED S. I. C. CODES

S. I. C. CODE

Source	Type of Price	23 Apparel & Other Textiles	26 Paper & Allied Prod.	28 Chemicals & Allied Prod.	29 Petroleum & Coal Prod.	30 Rubber & Plastics	32 Stone Clay & Gloss Prod.	33 Primary Metals	34 Fabricated Metal Prod.	35 Machinery Except Electrical	36 Electrical Equipment & Supplies
Econometrica International (1976)	A	-.82	-.82	-2.09	-1.71	.15	-.30	-.72	-.84	-2.69	1.34
Halvorsen (1977)	A	-.15	-.20	- .68	-1.03	-.12	-.31	-.83	-1.10	- .79	-.27

NOTES:

1. A = Average price
2. Reported Econometrica International estimates are for a Cobb-Douglas cost function.
3. All elasticities are long-run.

EXHIBIT IV-9

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

PROJECTED PERCENTAGE CHANGES IN INDUSTRIAL CONSUMPTION RESULTING FROM THE IMPLEMENTATION OF RATE LEVELS GIVEN IN EXHIBIT III-4 FOR SELECTED S. I. C. CODES

		S. I. C. CODE			
		23	26	33	34
General Service - Large					
Current Rate					
PSP&l		0.0	0.0	0.0	0.0 *
PP&L		0.0	0.0	0.0	0.0
WWP		0.0	0.0	0.0	0.0
TAECOS					
PSP&L	from	+18.38	+18.38	+16.14	+18.83
	to	+ 3.36	+ 4.48	+18.59	+24.64
PP&L	from	+13.00	+13.00	+11.41	+13.32
	to	+ 2.38	+ 3.17	+13.16	+17.44
WWP	from	- 6.47	- 6.47	- 5.68	- 6.63
	to	- 1.18	- 1.57	- 6.52	- 8.54
MCOS					
PSP&L	from	-139.99	-139.99	-122.92	-143.40
	to	- 25.61	- 34.14	-141.68	-187.77
PP&L	from	-158.76	-158.76	-139.40	-162.63
	to	- 29.04	- 38.72	-160.69	-212.96
WWP	from	-226.67	-226.67	-199.03	-232.20
	to	- 41.46	- 55.28	-229.41	-304.04
General Service - High Voltage					
TAECOS					
PSP&L	from	+11.30	+11.30	+ 9.92	+11.58
	to	+ 2.07	+ 2.76	+11.45	+15.18
PP&L	from	+19.91	+19.91	+17.48	+20.40
	to	+ 3.64	+ 4.85	+20.13	+26.68
WWP	from	- 9.74	- 9.74	+ 8.55	+ 9.98
	to	- 1.78	- 2.37	- 9.84	-13.04

* Indicates current rates, no change.

EXHIBIT IV-9 cont.

MCOS

PSP&L	from	-126.23	-126.62	-111.19	-129.72
	to	- 23.09	- 30.79	-127.78	-169.35
PP&L	from	-100.87	-100.87	- 88.57	-103.33
	to	- 18.45	- 24.60	-102.09	-135.30
WWP	from	-188.21	-188.21	-165.26	-192.80
	to	- 34.43	- 45.91	-190.53	-252.51

NOTES:

1. See Test for Computational Methodology

2. This is a *ceterius paribus* analysis.

3. TAECOS refer to Traditional Average Embedded Cost of Service. MCOS refers to Marginal Cost of Service.

4. All estimates are long-run.

EXHIBIT IV-10

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

PERCENTAGE CHANGES IN ON-PEAK DEMAND (KW) AND CONSUMPTION (KWH)

DERIVED FROM TABLE VII

May 1976-May 1977

	KW	KWH
Steel Mills	-76.0	-71.0
Cement Hydraulics	-65.0	-46.0
Converted Paper Products	-13.0	- 8.0
Industrial Gases	-15.0	- 8.0

NOTES:

1. Figures are approximations.
2. KWH computed by Simpson's discrete approximation.

SECTION V

THE ALLOCATIONAL EFFICIENCY OF ALTERNATE RATE STRUCTURES

INTRODUCTION

At any point in time, the economy is characterized by a particular arrangement of activities and resources. This arrangement is described by specific consumption levels for each consumer, by specific input and output levels for each producer and by a particular distribution of the rewards of the economy. Implicitly, this arrangement has been selected over all other possible alternatives. The question which naturally arises is whether or not this state is, by some definition, efficient. If it is not, then it would be socially desirable to move to some alternate economic state. The concept of efficiency is of practical importance because it implies that goods must be consumed and produced in a particular manner in order for efficiency to be obtained. In a regulated industry this will have important implications for how rates and prices are set. Thus, in analyzing the allocational efficiency of alternate rate structures, four questions must be addressed. These questions are: (1) What constitutes a reasonable definition of efficiency, (2) What implication does this definition of efficiency have for the manner in which resources are allocated to production and consumption in the economy, (3) What impact does price have on allocating resources in the economy, and (4) What constitutes an efficient set of prices.

A DEFINITION OF ALLOCATIONAL EFFICIENCY

Pareto optimality[1] provides a definition of economic efficiency which serves as a basis for much of the analysis in economics. Specifically, all allocation is Pareto optimal if production and consumption cannot be redistributed in such a way as to make one or more individuals better off without making any individual worse off.[2] Conversely, all allocation is non-Pareto optimal if some individual's position can be improved without a deterioration in any other individual's position. Note that this definition is limited in the sense that it says nothing about the desirability of a reallocation of resources which harms one individual while benefitting another. It simply states that once a move to an alternate economic state has been made there is always a better move to a Pareto-optimal position. As Paul Samuelson states, "Pareto shows that however desirable such a move may be, there exists still a better move, which for the same (ordinal) amount of harm to those who 'should' be harmed, will yield more benefit for the worthy ones who are to be benefitted. This is an important contribution."[3]

THE CONDITIONS FOR PARETO OPTIMALITY

Pareto optimality has been defined as criterion for measuring efficient allocation of resources. The question now becomes whether this abstract notion has any practical implications for the way goods are produced and consumed in the economy.

The answer is yes. Specifically, there are five necessary[4] conditions for Pareto optimality. Some of these conditions will have direct applications to relevant issues in designing of utility rates. This section will address these conditions for Pareto optimality.

Imagine a very simple barter economy in which there are two consumers. Assume that one consumer possesses all of the island's water and the other all of the island's food. Under ordinary circumstances, we would expect these two individuals to trade. Why do they trade? Clearly, because the exchange is mutually beneficial. The first allocation of resources was not Pareto optimal and by reallocation (trading) both individuals became better off. The economy moved from a Pareto nonoptimal situation to a Pareto optimal situation. Now we ask the question, what caused the trading to begin and what caused it to stop. Define the rate of commodity substitution as the amount of water an individual is willing to give up for a set amount of food and still be indifferent (i.e., feel no increase or decrease in utility). In general, if the consumers' rates of commodity substitutions are not equal, then they will trade. To illustrate, if one individual is willing to give up two gallons of water for one unit of food, then his rate of commodity substitution is 2 to 1. Hypothesize that the rate of commodity substitution between water and food for one individual is 2 to 1 and for the other it is 4 to 1. This situation is Pareto nonoptimal because one consumer is willing to trade one unit of food in return for four units of water while the other consumer only requires two units of water for one unit of food. They will trade (reallocate) resources and each will be better off. This trading processes will continue until the consumers' rates of commodity substitution equilibrate.[5] This is the first condition for Pareto optimality.

Now assume that there is a production side to the island economy. That is, there are firms producing water and food using two[6] inputs to production labeled X_1 and X_2 (these can be visualized as labor and machinery). Define the rate of technical substitution as to the amount of one input which must be substituted for the other in order to keep production constant. To illustrate, suppose one producer finds that he can maintain his current level of output if he substitutes three workers for one machine. Thus, his rate of technical substitution between labor and capital is three to one at that level of output. Pareto optimality in production requires that the rates of technical substitution between producers be equal. Assume that one producer's rate of technical substitution between labor and capital is three to one, while another producer's is four to one. Then, we could reallocate one unit of capital from the first to the second producer. The second producer could <u>then give up four units of labor</u> and keep his output constant. These four units of labor could then be reallocated to the first producer which, since he only required three units to maintain his production level, will <u>increase</u>[7] his output. With the same amount of resources, reallocation has increased the production of one good without decreasing the output of the other. Under normal circumstances, there has been a move to a Pareto superior position. This exercise will always be possible unless the producers' rates of technical substitution are equal. This is the second condition for Pareto optimality.

Note that at any point in time, the economy is allocating scarce resources for the production of goods. Whenever a good is produced, an opportunity cost is incurred. The resources that are used in producing this good <u>could</u> have been applied to the production of a different good. For example, when an automobile is produced, the economy foregoes the opportunity of using the steel and labor in other uses. Define the rate of product transformation (RPT) as the additional output of one good which the economy could obtain by curtailing the output of another good. Thus, if the production of fifty automobiles is eliminated, and enough steel, labor, etc. is freed to produce one bridge, then rate of product transformation between these goods is fifty to one. This leads to the Pareto condition which has captured the most attention in the utility industry. This condition implies that in a perfectly competitive environment price must be equal to marginal cost.

The third condition for Pareto optimality is that the rates of commodity substitution for all consumers must be equal to the rates of product transformation for every pair of produced goods. Suppose that the rate of commodity substitution between two goods, X_1 and X_2 is one to three for some consumer. Recall that this implies the consumer is willing to trade three units of X_2 for one unit of X_1 and be indifferent. Furthermore, assume that the rate of product transformation for these goods is two to three. If the consumer surrendered three units of X_2, this would free enough resources to allow the economy to produce two units of X_1. The consumer's satisfaction could thus be increased by performing this technical transformation. This is true whenever producer rates of product transformation are not equal to consumer rates of commodity substitution.

Whenever production is occurring and more of a factor of production is added, it would normally be expected that total production would increase. An example of this would be the addition of a worker to a firm. The total output of the firm increases. Define the marginal product of a factor as the rate at which output increases with the addition of that factor. Note also that many factors of production in the economy are also consumption goods. Labor is a prime example. Certainly a factor of production, labor is, also, consumed in the form of leisure. Hypothesize that a consumer's rate of commodity substitution between X_1 and X_2 is used to produce X_2 (water and food is an interesting example) and that an additional unit of X_1 applied to the production of X_2 will result in an increment of twelve units. If the consumer gives up one unit of X_1, it can be reallocated to the production of X_2 resulting in twelve units. The consumer's satisfaction is increased by this transformation. Pareto optimality requires that the rates of commodity substitution between a factor and a good be equal to the factor's marginal product in the production of that good. This is the fourth Pareto condition.

The fifth Pareto condition states that for all primary goods (factors of production) that the rates of commodity substitution for all consumers be equal to the rates of technical substitution for all producers. To illustrate, suppose that the rate of commodity substitution between X_1 and X_2 is two to one for some consumer and the rate of technical substitution between X_1 and X_2 is three to one for some producer. This implies that the producer can give up three units of X_1 if he receives one unit of X_2 and still keep his output constant. Thus, the consumer can increase his satisfaction by trading one unit of X_2 for three units of X_1 while the producer's output remains constant. Such an exchange is not possible if the rates of commodity substitution are equal to the rates of technical substitution.

Summary

In general, the five Pareto first-order conditions are:

1. The rates of commodity substitution of all produced and primary goods for all consumers must be equal.

2. The rates of technical substitution of all primary goods for all producers must be equal.

3. For all produced goods, the consumer's rate of commodity substitution must be equal to the producer's rate of product transformation.

4. For all primary goods used in production and consumption, the consumer's rate of commodity substitution between the factor and the produced good must be equal to the factor's marginal product in the production of that good.

5. For all primary goods, the consumer's rate of commodity substitution must equal the producer's rate of technical substitutuion.

THE IMPLICATION OF PRICES

The conditions for Pareto optimality, examined in the last section, were defined in terms of physical rates of substitution between factors and commodities without reference to prices. But prices are important determinants of how consumers and producers allocate their consumption and production. The market implicitly allows consumers to trade (re-allocate) their consumption of goods in ratios determined by prices. Suppose that one good is priced at $2.00 and another at $1.00. If the consumer curtails his consumption of the $2.00 good by one unit, he frees enough income to buy two units of the $1.00 good. The market has allowed him to trade the goods in a two to one ratio which corresponds to the ratio of the good's prices. Prices impact consumption for they set the terms of trade.

Similarly, prices are important determinants of production. When a good is in short supply, or high demand, prices rise. This causes a greater discrepancy between the final price of the product and the prices of the material inputs needed to produce it. Optimal production levels will rise. The industry increases its demands for inputs and bids these resources away from other uses in the economy. Resources have been reallocated to increase production levels of this good. The whole process has been signaled and accomplished through changes in prices.

Pareto optimality should be achieved if consumers and producers adjusted their consumption and production to efficient prices. The question of interest, is whether particular rate structures constitute efficient prices. The answer requires two steps of analysis. The first step is to determine how prices impact consumption and production. The second step is to integrate this situation with the analysis of Pareto optimality and derive the implications for rate structures.

Recall that the rate of commodity substitution (RCS) is defined as the amount of one good a consumer will give up in return for another and still be indifferent. Consumers will determine their consumption levels by setting the rate of commodity substitution between two goods equal to their price ratio.[8] Assume that the prices of two goods, X_1 and X_2, are both \$1.00.

If a consumer's rate of commodity substitution between X_2 and X_1 is three to one, this implies that he is willing to give up three units of X_2 and requires only one unit of X_1 and still be indifferent. But at the market prices, if the consumer gives up three units of X_2, he frees \$3.00 in income which can be used to purchase three units of X_1. The consumer would spend his income on X_1 and not on X_2. Conversely, assume that a consumer's rate of commodity substitution between X_1 and X_2 is one to three. Analogously, the consumer would spend his income wholly on X_2. It has been demonstrated that when the rate of commodity substitution is either greater or less than the price ratios, the consumers do not purchase both goods. The conclusion is that consumers who consume both X_1 and X_2 will set their rate of commodity substitution for these goods equal to their price ratio.

Examine a very simple situation in which a firm is producing one output, Q, using only one factor of production, X. Define the marginal cost of production as the additional cost that the firm must incur in order to increase output of Q by one unit. In this circumstance, the marginal cost would be equal to the price of X, divided by its marginal product. Recall that if the marginal product of X is two then the firm purchases one more unit of X, it obtains two more units of Q. If the price of X is \$5.00, then the marginal cost of producing one more unit of Q is \$2.50; the price of X divided by its marginal product. Competitive firms will determine their output level by equating the price that they receive for their product to the marginal cost of production.[9] Assume that the price the firm is receiving for Q is \$5.00, then clearly the firm would find it profitable to expand production. It can produce one more unit of Q generating \$5.00 in revenue by purchasing only 1/2 unit of X and incurring only \$2.50 in cost. The firm will expand production when price is greater than marginal cost. Conversely, suppose the price of Q was only \$1.00. In this circumstance, the firm would probably decrease production. By decreasing production the firm sacrifices \$1.00 in revenue but incurs \$2.50 less in cost. To conclude, at the optimal production level, the firm will equate price to the marginal cost of production.

In summary, it has been shown that prices impact consumption and production in the following manner:

1. Competitive consumers will optimize consumption by setting the rate of commodity substitution between goods equal to the ratio of the goods' prices.

2. Competitive producers will set a profit optimizing production level by equating price equal to the marginal cost of production.

3. For each input into production, the marginal cost of output in terms of that input, is equal to the price of the input divided by its marginal product.

RATES

The conditions for efficiency have been defined and the impact of prices on consumption have been examined. The question of what constitutes an efficient rate structure can now be addressed.

The first condition for Pareto optimality was that the rate of commodity substitution of all produced and primary goods for all consumers be equal. Also, it was concluded that optimizing consumers will determine their consumption level by equating their rate of commodity substitution between goods to the ratio of their prices. If all consumers are charged the same price for the same good, then the first condition of Pareto optimality is fulfilled This is an argument for equitability in rate structures. This point is particularly relevant in connection with lifeline rates.

The inefficiency of nonequitable rates deserves some clarification. First, these rates are an inefficient method of redistributing income to the recipient of the lower prices. While the recipients clearly benefit from the rates, they would always prefer to have the value of the subsidy in income. Define the value of the subsidy as the difference between the expenditures made under the lower rates and the expenditures that would have been made when purchasing the same amount of electricity under the higher rate structure. With income, consumers can still purchase the same amount of electricity as under the lower rates, but they have the option of purchasing other goods. Under this plan consumers can be better off, but no worse off, than under a nonequitable rate structure. Secondly, given the option, separate consumers under nonequitable rates would always trade.[10] This is a result of their rates of commodity substitution being unequal.[11] Consumers paying the higher prices would attempt to purchase electricity from the lower rate consumers to decrease consumption costs. The lower rate consumers would sell electricity to generate income to purchase other goods. Of their own will, consumers realloated the distribution of electricity in consumption. The first distribution (obtained through inequitable rates) was Pareto nonoptimal.

The third condition for Pareto optimality implied that the rate of commodity substitution for all consumers between produced goods be equal to the economy's rate of product transformation between these goods. Visualize a primay factor of production X which can be used as a input to produce two goods, Q_1 and Q_2. Assume that the marginal product of X in the production of both of these goods is one. Then one more unit of X applied to either the production of Q_1 or Q_2 yields an additional unit of output. The economy's rate of product transformation between Q_1 and Q_2 is one to one, for the economy can produce one more unit of Q_2 by curtailing the production of Q_1 one unit and freeing a unit of X. This rate of product transformation between Q_1 and Q_2 is defined as a ratio of the inverse of the marginal product of X in the production of these goods. Recall that a competitive firm will optimize its production level by setting price equal to marginal cost. The marginal cost for each input will be defined as a ratio of the price of the input to the marginal product of that input in the production of the good. In conclusion, if all firms in the economy equate price to marginal cost, then the rate of product transformation between all goods will be set equal to the ratio of final prices of these goods. Consumers will optimize consumption by setting their rates of commodity substitution equal to these same price ratios. Thus the third condition of Pareto optimality will be met if all firms set price equal to marginal cost.

These results can be summarized in the following manner. Consumers will set their RCS between Q_1 and Q_2 equal to their price ratio. Mathematically,

$$1)\quad R.C.S. = \frac{P_{Q_1}}{P_{Q_2}} \qquad \text{where } P_{Q_1} = \text{Price of } Q_1$$

Firms will set the price of their product equal to its marginal cost. The marginal cost will be equal to the price of x divided by its marginal product. The economy's rate of product transformation between Q_1 and Q_2 (R.P.T.) is equal to the inverse of these marginal products. Mathematically,

$$2)\quad \frac{P_{Q_1}}{P_{Q_2}} = \frac{MC^x_{Q_1}}{MC^x_{Q_2}} = \frac{P_x/MP_x^{Q_1}}{P_x/MP_x^{Q_2}} = \frac{1/MP_x^{Q_1}}{1/MP_x^{Q_2}} = R.P.T.$$

Combining 1 and 2, yields the third condition for Pareto optimality:

$$3)\quad R.C.S. = P_{Q_1}/P_{Q_2} = \frac{MC_{Q_1}}{MC_{Q_2}} = \frac{P_x/MP_x^{Q_1}}{P_x/MP_x^{Q_2}} = \frac{1/MP_x^{Q_1}}{1/MP_x^{Q_2}} = R.P.T.$$

where: MC_{Q_1} = marginal cost of Q_1

P_x = price of X

MP_xQ1 = marginal product of X in the production of Q_1

The above proof implies that for an optimal allocation of resources, price must be equal to marginal cost for <u>every</u> commodity. The implication of this analysis for rate structures is that under general conditions it can be concluded the marginal cost pricing will lead to the most efficient allocation of the economy's resources. Rate structures which deviate from marginal cost would, under these assumptions, lead to nonoptimal allocations of resources.

Another implication of this analysis is of interest. Equation 2 implies that the competitive firms producing Q_1 will optimize production by:

$$4)\quad P_{Q_1} = MC_{Q_1} = P_x/MP_x^{Q_1}$$

$$4^1) \quad MP_x^{Q_1} = \frac{P_x}{P_{Q_1}}$$

But, competitive consumers will equate their R.C.S. between X and Q_1 to this ratio. Thus we can write:

$$5) \quad MP_x^{Q} = \frac{P_x}{P_{Q_1}} = RCS^x_{Q_1}$$

This is the fifth condition of Pareto optimality. If competitive consumers and producers are charged the same prices for primary factors, then the consumers RCS between factors and commodities will equal the producers rate of transforming factors into commodities (i.e., their marginal products). It has already been demonstrated that efficiency requires equality in prices charged to consumers. This analysis extends the argument to equality in prices among consumers and producers purchasing primary factors of production. Together these conditions provide strong arguments for comprehensive equitablitity in rate structure designs.

CAVEATS

The analysis, thus far, has concluded that marginal cost pricing would lead to the most efficient allocation of resources in the economy. In this section, two questions are to be considered: 1) Are there any conditions under which marginal cost pricing would not lead to efficient allocation of resources? and 2) Are there any criteria for ranking the allocational efficiency of nonmarginal rate structures?

In general, the exceptions raised to the efficiency of marginal cost pricing fall into three categories: eternal economies and diseconomies, the theory of second best and dynamic adjustment problems.

The analysis which has been presented assumes that there are no external economies or diseconomies in either production or consumption. Basically this implies that the utility level of a consumer does not depend upon the consumption level of others and that the total costs, or the technical constraints of a firm, do not depend upon the output levels of other firms. Clearly, this is an unrealistic assumption. Goods exist, commonly termed public goods, which are consumed collectively. Examples are public parks and highways. External diseconomies such as water and air pollution cause deviations between social costs and market prices. It is generally asserted that the effects of these external economies and diseconomies can be ameliorated through a series of appropriate taxes subsidies and compensation.

The theory of second best presents a different objection to the optimality of marginal cost pricing. The previous analysis asserted marginal cost pricing would lead to Pareto optimality if every commodity in the economy was priced at marginal cost. Thus, if every good in the economy was priced at marginal cost except one, a positive social dividend would be obtained by pricing the final good at its marginal cost. This is a definitive statement, but it does not extend further. Suppose that more than one commodity has a price which is nonreflective of marginal costs. Is there necessarily any gain in allocational efficiency by moving the price of only one of these goods to marginal cost? The answer is no. In general, the theory of second best asserts that if one of the condtions for Pareto optimality cannot be met, it is neither necessary nor desirable to satisfy the remaining conditions. This has several critical implications for the design of efficient rate structures. If the full benefits of efficient pricing in allocating resources are to be realized, then all production and consumption in the economy must be priced in an efficient manner. Second best demonstrates that if one sector of the economy is priced efficiently, then the benefits of competition in all other sectors of the economy can be dampened or nullified. It is also known that the effects of imperfect pricing in one market are minimized if that market is separable from other goods in both consumption and production. For example, the sugar and airline manufacturing industries are probably very distantly related to each other. The impact of imperfect pricing in the sugar industry upon the airline manufacturing industry is likely to be minimal. It should not concern us that the sugar industry is nonmarginally cost priced when examining whether or not to price the airline manufacturing industry at marginal cost. Two important points should be noted. First this emphasizes the importance of efficient pricing in the electric utility industry. This is because the electric industry is, in a practical production sense, intertwined with a wide variety of industries thoughout the economy. Secondly, there is a current trend toward deregulating the prices of close energy substitutes for electricity, such as natural gas and oil. If the full benefits of deregulation are to be obtained, then the efficient pricing of electricity is crucial.

Even if no external economies or diseconomies exist and there are no problems of second best, it is not unambiguously beneficial for society to force electricity pricing at marginal cost. There will be a social dividend obtained in moving to the marginal cost position, but this is an exercise in comparative statics. The conclusion has been reached that one point is superior to another, but no analysis of the dynamic path (and its inherent costs) that the economy must follow in adjusting to marginal cost pricing has been performed. It is possible that these costs eclipse any benefits that might be realized. The administered nature of electricity prices, coupled with present static computations of marginal costs, may even dictate a dynamic path which never converges to marginal costs (i.e., the path is unstable). As with all costs, marginal costs usually depend upon the level of production. On-peak marginal costs are typically greater than off-peak costs because demand is higher and presses upon system capacity. When prices are altered, consumption patterns shift. In turn, this shift changes the marginal costs of the system. Prices are adjusted to the new marginal costs. This again alters demand characteristics which alter costs dictating another price change. The assertion that this adjustment process converges implies restrictions upon how both costs and demand respond to changing output and price levels. (As an aside, this analysis is not typically undertaken by marginal cost advocates.)

Administrative and allocational costs (as short-run deviations from marginal cost occur) are incurred with this adjustment path and should be examined in detail.

The final question to be addressed is how rate structures which are not marginally cost oriented might be ranked in terms of allocational efficiency. This question is usually addressed in connection with revenue requirements which do not allow a utility to fully recover marginal costs. It can be demonstrated that if efficient pricing is desired, subject to the institutional constraint that revenues must not exceed a fixed level, then it is optimal to deviate most from marginal cost when pricing for those consumers who have inelastic demands for electricity. This is known as the inverse elasticity rule. Intuiitively, the rationale behind this rule can be visualized in the following manner.

Define price elasticity as the percentage change in the consumption of electricity that occurs with a given percentage change in the price of electricity. If the price of electricity goes up 1% and a given consumer customer class decreases its consumption by 1%, then the elasticity is -1. If the price of electricity goes up by 2% and the customer class decreases its consumption by 1%, then the elasticity is -.5. If the elasticity is less than -1, note in this case the percentage change in quantity is greater than the percentage change in price, demand is termed elastic. If the elasticity is greater than -1, then the demand is termed inelastic. Examine the extreme case where the elasticity of the demand is zero. This implies that the percentage change in quantity with any given percentage change in price is zero, i.e., no matter what the price, consumers purchase the same quantity of the good. Recall that the goal of economic efficiency is to allocate the levels of production in an optimal manner. If nonefficient prices are charged to a buyer whose demand is highly inelastic, his consumption does not vary significantly from optimal levels. Conversely, consumers with more elastic demands would alter to a greater degree their consumption away from the optimal levels. Thus if deviations must occur away from the efficient price, it is optimal for the greatest deviations to occur in customer classes with the most inelastic demands.

In this context, it is of interest to examine price elasticity estimates by typical rate structure customer class delineations. These issues have been discussed in detail in Section IV. Briefly, Exhibit V-1 presents a survey of recent econometric estimations of price elasticities of residential electric energy demand. Several points should be emphasized. First note that the table presents both short and long run price elasticities. The short run price elasticities would measure the impact of a change in the price of electricity on the demand for electricity over a short run period of time, such as one year. The long run elasticity estimates would measure the impact of a price change over a long run period of time as consumers adjust their stock of electricity using devices to the new prices. Roughly, the long run cumulative impact would be felt over a period of 20 years. As expected, the short run price elasticity estimates are very inelastic, ranging from -.07 to -1. The long run price elasticity estimates are more elastic, ranging from -.7 to -1.89. Care must be taken in applying these elasticities specifically to Washington State and any utility therein. Most of these studies were performed using national data and the elasticities represent an average national estimate. There are strong reasons to believe that significant regional and utility differences would exist in electricity price elasticities. For example, we would expect price responses in an area of extensive electric space heating to vary significantly from price responses in an area of extensive natural gas space heating. Nevertheless, these ranges probably provide reasonable bounds.

Exhibit V-2 presents econometric estimates of electric energy price elasticities for industrial users by standard industrial classification code. The range is from -.124 to -1.096. The most inelastic estimate (-.124) was for the rubber and plastics industry. The most elastic (-1.096) was for the fabricated metal products industry. This table illustrates several points. First, it is clear that the response of industrial consumers to electricity prices varies significantly across industries. This is to be expected because different industries would have varying energy intensities and differing growth rates. This is an important finding which vividly illustrates that traditional rate delineations by customer classes do not address the question of optimal allocation effectively. These price elasticity estimates imply that by applying one rate structure to the entire industrial class, allocational distortions are introduced which vary significantly across industries. As with the residential elasticity studies, industrial elasticities were derived from national data and care must be taken in applying them on a regional or utility basis.

Exhibit V-3 presents price elasticity estimates for the commercial sector. The brevity of the table is reflective of a general lack of research into this question. The elasticity estimates range from -.916 to -1.6. As with both the residential and industrial tables, these estimates were derived using national data and are not strictly applicable on a regional or utility basis.

To conclude, the inverse price elasticity rule implies that if for revenue reasons it is necessary to charge nonefficient prices, then it is optimal to deviate most with those customers that have the most inelastic demands. Econometric estimates of price elasticities by traditional rate delineations have demonstrated two important points. First, there are significant differences in price responses by customers in the same class. This implies traditional rate structure categories do not adequately address the questions of allocational efficiency under revenue constraints. Second, examine the actual price elasticity estimates given in Exhibit V-1 through V-3 for the residential, industrial and commercial sectors. Observe that the estimates do not significantly change across customer classes. Thus, the arguments of allocational efficiency and the inverse elasticity rule do not, in general, support rate discrimination across customer classes.

CONCLUSIONS: ECONOMIC EFFICIENCY AND ALTERNATIVE RATE STRUCTURES

The impact of nonmarginal cost rates in marginal cost market is clear: Allocational efficiency suffers. The impact of nonmarginal cost rates in a market where numerous other goods and services are nonmarginally priced is less clear. As a matter of theory, it is not obvious that allocational efficiency is greatly harmed, or even necessarily affected by nonmarginal cost rates. It may even be that marginal cost prices in such markets will degrade existing allocational shares manifested in the market. The apparent rule would be to restrict marginal cost rates to markets in which marginal cost prices generally prevail. The second best rule reminds us that any departure from such conditions must be with caution. In this vein, suggetions have been made for various kinds of compromises in pricing which turn on the market imperfections confronting the seller.

The impacts of nonmarginal rates in the utility industry turns on the quantity of energy consumed in the market and the sensitivity of consumers to rates. Obviously, the effects of nonmarginal rates could be very substantial. Where the price sensitivity of electrical services is great and the quantity large, there is reason to carefully consider the state of the market and the rates charged consumers. As either quantity or sensitivity decreases, there is relatively less concern.

In general, it is probably true the American economy does not represent a marginally priced market, nor even well defined marginally organized energy submarkets. In such circumstances, the benefits of marginal cost rates are doubtful, or at least open to serious question. This conclusion leads to an important reservation regarding price policy.

The fact that consumers tend to use less energy the higher the price of energy offers little reflection on the benefits or costs of marginal cost rates. Price will always ration demand. The key question is whether society is also served by a superior allocation of resources.

The correct level of conservation is that level which is induced by efficient prices. Any other means of conservation inducement such as nonmarginal prices intentionally designed to reduce (or "conserve") consumer demands for capacity or energy are not appropriate if economic efficiency is also a goal.

To conclude, under a set of general assumptions which have been discussed in detail, economic theory asserts marginal cost pricing leads to allocational efficiency. A priori, there is no basis for ranking nonmarginal rate structures in terms of allocational efficiency.

SECTION V FOOTNOTE PAGE

1 For a complete mathematical exposition of optimality, see Henderson, 1971.

2 i. e. utility decreases.

3 Foundations of Economic Analysis, page 214.

4 These conditions are derived under a set of specific assumptions. For details, refer to Henderson, 1971.

5 Strictly interpreted, the Pareto conditions are inequalities and the analysis should consider Kuhn-Tucker provisions. For a complete discussion, see Samuelson, 1976.

6 The argument generalizes to n factors of production and n produced goods.

7 If the marginal product is positive.

8 This conclusion holds under a set of specific assumptions. See Henderson, 1971.

9 This conclusion holds under a set of specific assumptions. See Henderson, 1971

10 We can conclude from this that one way of eliminating the inefficiency of life-line rates, in consumption, would be to establish a "white" market in energy coupons. These coupons would allow the bearer to purchase a set amount of electricity at life-line rates.

11 For details, refer to previous discussion.

EXHIBIT V-1

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ECONOMETRIC ESTIMATIONS OF PRICE AND INCOME ELASTICITIES OF RESIDENTIAL ELECTRICITY DEMAND

Source[c]	Type of Price[b]	Price Elasticity Short-run	Price Elasticity Long-run	Income Elasticity Short-run	Income Elasticity Long-run	Type of Data
Fisher-Kaysen (1962)	A	-0.16 to -1.00	N.A.	-0.15 to 0.89	-0.18 to -0.78	TS: By state
Houthakker-Taylor (1970)	A	-0.13	-1.89	0.13	1.93	TS: Annual aggregate U. S.
Wilson (1971)	A	N. A.	-1.33	N. A.	-0.46	TS: Cities
Mount, *et al.* (1973)	A	-0.14	-1.21	0.03	0.03	CS-TS: States
Anderson (1973)	M	N. A.	-.091[a]	N. A.	1.13	CS: States
Lyman (1973)	A	N. A.	-0.90	N. A.	-0.20	CS-TS: Utilities
Acton, *et al.* (1975)	M	N. A.	-0.70	N. A.	0.40	CS: Small geographic areas
	M	(-0.34)		(0.41)		CS: Small geographic areas
Taylor, *et al.* (1975)	M	-0.97	-0.78	0.10	1.18	TS: States
Lacy-Street (1975)	M	(-0.45)		(1.87)		TS: One utility are

EXHIBIT V-1 Cont.

Wilder-Willeborg (1975)	A	-1.00	-1.31	0.16	0.34	CS: Individual households
Uri (1975)	A	-0.61	-1.66	0.04	0.12	TS; Monthly aggregate U. S.
FEA (1976)	A	-0.19	-1.46	0.30	1.10	CS-TS: Census regions
Halvorsen (1976)	M	N. A.	-0.97	N. A.	0.70	CS: States
McFadden-Puig (1975)	A&M	N. A.	-0.22 to -0.71	N. A.	0.99	CS: States
Taylor (1977)	M	-0.07	-0.81	0.09	1.05	CS-TS: States
Taylor (1977)	I	-0.01	-0.14	0.09	1.05	CS-TS: States
Russell (1978)	M	-0.09	-0.41	0.24	1.11	TS-CS: Utility Service Area
Russell (1978)	I	-0.06	-0.26	0.24	1.11	TS-CS: Utility Service Area

a. With appliance saturations fixed, a price elasticity of -0.63 was obtained.

b. A = average price; M = marginal price; I = Intermarginal

c. This is drawn in part from McFadden (1977).

EXHIBIT V-2

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ECONOMETRIC ESTIMATIONS OF PRICE ELASTICITIES FOR INDUSTRIAL ELECTRICITY DEMAND

BY SELECTED S. I. C. CODES

S. I. C. CODE

Source	Type of Price	23 Apparel & Other Textiles	26 Paper & Allied Prod.	28 Chemicals & Allied Prod.	29 Petroleum & Coal Prod.	30 Rubber & Plastics	32 Stone Clay & Gloss Prod.	33 Primary Metals	34 Fabricated Metal Prod.	35 Machinery Except Electrical	36 Electrical Equipment & Supplies
Econometrica International (1976)	A	-.82	-.82	-2.09	-1.71	.15	-.30	-.72	-.84	-2.69	1.34
Halvorsen (1977)	A	-.15	-.20	- .68	-1.03	-.12	-.31	-.83	-1.10	- .79	-.27

NOTES:

1. A = Average price
2. Reported Econometrica International estimates are for a Cobb-Douglas cost function.
3. All elasticities are long-run.

EXHIBIT V-3

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

ECONOMETRIC ESTIMATIONS OF PRICE ELASTICITIES
FOR COMMERCIAL ELECTRICITY DEMAND

Source	Type of Price	Price Elasticity Short-Run	Price Elasticity Long-Run	Type of Data
Mount, et al (1973)	A	-.20	-1.60	CS-TS: States
Halvorsen (1976)	A	N. A.	- .92	CS: States
McFadden (1972)	A	N. A.	- .73	CS: States
McFadden (1972)	M/A	N. A.	- .55	CS: States

Where:

A = Average Price
M = Marginal Price
CS = Cross-sectional
TS = Time Series

SECTION VI

CONCLUSIONS AND RECOMMENDATIONS

Detailed conclusions and recommendations in relation to cost, conservation and allocational efficiency are not justified by the study methods employed in the project. Specifically, the absence of system cost studies makes it impossible to state precise conclusions. Nonetheless, the study does emphasize a number of issues which deserve further exploration. At that time, it may be possible to reach precise conclusions and proceed to specific recommendations to fulfill policy objectives.

CONCLUSIONS AND RECOMMENDATIONS

The study concludes the following in regard to the three Washington Utilities:

1. CONCLUSION: Compared to the estimated costs of services, the rates of the three investor owned utilities are more or less typical of the United States electrical industry. There would be material benefit in consolidation, simplification and modernization of rates in all utilities.

   RECOMMENDATION: The Washington Utilities and Transportation Commission may desire to review the benefit of greater standardization of utility rate structures in which consolidations, simplificatioon and justification of specific design and level differences are explored. Such steps would make possible the comparison of utilities, would likely enhance consumer response to rates and could reduce the costs of rate administration by the utility.

2. CONCLUSION: It would appear that none of the three utilities has set rates based on an awareness of average embedded costs of service. In general, each utility appears to be charging residential users somewhat less, in proportion to cost, than is charged general service and industrial customers. This conclusion suggests that rate equity, based on average embedded cost recovery, may require attention, if rate equity at this cost level is desired. A policy of offering residential service at lower rates is common in the United States.

   RECOMMENDATION: The WUTC may desire to explore whether each consumer class is paying its average embedded costs of service and the proportion of cost each pays. This information would provide a measure of rate equity, if it is first assumed that costs of service have been allocated properly. A number of allocation methods are available for use in cost of service studies. Selection of allocation methods should be based upon an understanding of the operational characteristics of each utility and those served.

   Also of concern is the problem of customer class definition and discrimination (due, undue or gross) among ratepayors in the same class. Classes should reflect more than common voltage levels or consumption characteristics which have historically been used as class determinants, and still be used, if cost related. Today, classes are becoming more rigorously defined based on the costs incurred in service to the class. If a classification is rational and rates are well related to class costs of service, legal discrimination problems as traditionally defined can be reduced or avoided. In this area of inquiry, it is helpful to recall two points: first, different unit rates for service between different classes of customers should be justified by different unit costs of service between the classes. Second, class definition by the utility (however done) should carry some measures of dispersion among members of the class as an indication of how generally the criterion apply. For example, if the average demand in a class of service is 10 and that number is employed to allocate capacity to the class, it is important to know what the class size is and the standard deviation of the demand within the class. The problem to be dealt with is appropriateness of class given the criterion employed. Today many load research programs permit good answers to these question.

3. CONCLUSION: It would appear that none of the utilities has set rates with respect to marginal costs of service. The existing rates of each utility are substantially lower than the range of marginal costs estimated for these utilities. This suggests that consumers of electrical services in Washington State may be using more energy than would be the case if marginal cost based rates were employed. Depending on consumer price sensitivity, this "overconsumption" of energy could be substantial. Long run price elasticity of demand estimates seem to suggest (all else equal) that over the relevant adjustment period each percentage point of real price increase will be met with and equal, or greater, reduction in the quantity of energy demanded. Therefore, while the changes in electricity consumption may be possible, the desirability is not so readily seen.

   RECOMMENDATION: The WUTC may desire to explore, in addition to marginal costs, a range of alternatives to full marginal cost prices. It is generally acknowledged that marginal costs are justified as benefitting allocational efficiency only under rigorous assumptions. Marginal cost rates might be charged ratepayors as a way of more accurately signaling costs of service and enhancing consumer awareness. Such a policy would accept that allocational efficiency is not a feasible goal and would instead seek only to let each consumer pay his way based on current costs.

   The implications of charging current cost rates (an alternative to future oriented marginal costs) turns in large measure on consumer price sensitivity. If consumer sensitivity exists, the quantity of electricity consumed will fall. This is in one view "conservation." Such conservation is not related to allocational efficiency; therefore it is not known for certain whether society is benefitted. On the other hand, if energy saving targets exist, a price policy might be the most efficient means to obtain desired conservation levels.

   Other alternatives to marginal cost rates can be examined for their contribution to providing more appropriate cost signals and for their impact upon conservation. Time differentiated average cost rates might be more appropriate for consumers where significant peaks exist. A higher rate during peaks could be a means of informing consumers what present consumption patterns will lead to in the future. This alternative rate design collects average costs, but does so by varying rates in time periods. If there is period price sensitivity, the quantity sold in the on-peak may fall, or stabilize, and revenues be reduced, or plateaued. Off-peak use may grow. Such alternatives to marginal cost are, therefore, not risk free and may have uncertain effects on net conservation as well. These problems notwithstanding, there are a number of reasons other than economic efficiency for reviewing the contribution of each to policy goals.

None of the alternative rate designs can be claimed to have a known effect on allocation efficiency in a mixed economy; therefore the pursuit of this goal should be set aside as a justificaton for this type of rate reform.

4. CONCLUSION: There are reasons to believe that consumers of electrical services in the three investor owned utilities would exhibit price sensitivity of the general direction and magnitude defined in the study. Nonetheless, the state of current research suggests that no policy should be adopted based on the accuracy of elasticity estimates alone. Caution and gradual adjustment of rates making limited use of elasticity data is concluded to be the best policy. The dynamic adjustment process of consumers suggests the need for a long term price perspective; time is required for the full realization of price impacts upon consumption.

RECOMMENDATION: Whether prices of electrical service have any allocational effect depends on the price elasticity of demand. If consumers are not influenced by price in making consumption decisions, demand is totally inelastic. This means that there is no price which will affect consumer decisions. Since total inelasticity is improbable, economists are typically interested in elasticity measures. Such estimates are recommended for Commission consideration because they are reasonably consistent in showing the direction and magnitude of consumer price sensitivity. Thus, elasticity estimates suggest the change in consumption that may be expected if real price levels are varied in specific ways. In each instance one can estimate the increased use, or reduced use, which will result from a change in price policy.

An investigation of price sensitivity is valuable in two added respects. Price elasticity data is also helpful in suggesting pro forma revenues, and the impact of a rate on consumer budgets.

Most utilities should be able to estimate the price elasticity of various consumer groups by making use of load data. Appropriate load research and forecasting programs would routinely provide these estimates.

To obtain cost-related, energy-conserving, efficient rates in Washington State, a major increase in the data collected and considered in the regulatory process is required. Clearly, cost of service studies, both average and marginal, are needed. Also necessary are load forecasts, elasticity estimates and service expansion plans and costs. With such data, a major effort can be mounted by the utility, staff and the Commission to determine what rate policies are supportive of goals under consideration. Currently, absence of such information hinders such a review.

END

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