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DOCKET NO. UE-92______________
WITNESS: D.W. HOFF

BEFORE THE
WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

COMPLAINANT

VS.

PUGET SOUND POWER & LIGHT COMPANY

RESPONDENT

TESTIMONY

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION
UE-920499 T-8

CONTENTS

SUMMARY OF RECOMMENDATIONS.............................. 2

FACTORS CONSIDERED IN DESIGNING RATES..................... 3

1. Impact on Integrated Resource Planning.............. 4

2. Results From Cost of Service Study.................. 5

3. Goals to Be Accomplished With Rate Design........... 5

4. Views of Interested Parties......................... 7

5. Power Supply Information............................ 8

GENERAL ISSUES OF RATE DESIGN THEORY..................... 14

1. Marginal Cost Pricing............................... 14

2. The Use of Elasticity Estimates..................... 19

3. Seasonal and Diurnal Power Costs.................... 20

4. Voluntary Rates and the Evaluation Process.......... 21

5. Base and Resource Cost Data......................... 22

RATE SPREAD PROPOSAL..................................... 23

RATE DESIGN PROPOSALS.................................... 26

1. Residential Rate Design............................. 27

   A. Issues... 27

   B. Specific Proposals............................... 32

   C. Summary of Recommendations....................... 38

2. General Service Rate Design......................... 38

   A. Issues... 38

   B. Specific Proposals............................... 41

3. Primary/High-Voltage Rate Design.................... 46

4. Other Rate Design Proposals........................ 48

a. Interruptible Rates for Large Users............ 48

(i) Interruptible Service Credit--Firm........ 50

(ii) Interruptible Service Credit--Non-Firm.................................... 57

b. Proposed Power Factor Adjustment............... 57

c. Seasonality in Demand Charges.................. 60

5. Allocation of PRAM Revenues........................ 62

PUGET SOUND POWER & LIGHT COMPANY
TESTIMONY OF DAVID W. HOFF

Q. Please state your name, business address and position with Puget Sound Power & Light Company.

A. My name is David W. Hoff, my business address is 411 - 108th Avenue N.E., Bellevue, Washington 98004 and I am Director rate planning and administration.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to translate the cost of service information presented by Ms. Lynch into rates that meet the objectives presented by Mr. Knutsen.

Q. How is your testimony organized?

A. I begin with a brief summary of my rate spread and rate design recommendations. Then I identify the factors and sources of information taken into account in developing my rate spread and rate design recommendations. This is followed by a more detailed discussion of rate design issues and my specific proposals.

Q. Please state your educational background and professional experience.

A. I have prepared a separate exhibit, Exhibit ___ (DWH-2), which sets forth my educational background and professional experience.

SUMMARY OF RECOMMENDATIONS

Q. Could you please summarize the findings and recommendations in your testimony?

A. Yes. My findings and recommendations may be summarized as follows:

Cost of Service

We are proposing a number of changes in the method by which the cost of service is determined. The results suggested by the proposed cost of service study indicate the following parity ratios:

Residential	Secondary	Primary	High Voltage	Lighting	Resale
.93	1.25	.95	.83	1.10	.96

Rate Spread

- We propose to spread rates in a manner that moves all of the parity ratios toward 1.00, thereby reducing the cross-subsidies which currently exist.
- In the interests of gradualism and rate stability, the specific rate spread proposal in this proceeding contemplates only partial movement of rates toward the ultimate parity goals. The proposed rate spread would produce the following parity ratios:

Residential	Secondary	Primary	High Voltage	Lighting	Resale
.96	1.17	.97	.89	1.06	.97

Rate Design

General

- We propose to add new schedules to make interruptible service available to a greater number of customers.

- We propose to change the method of adjusting bills for poor power factors.
- The seasonal differential for energy charges is proposed to be increased from 5% to 10%, and we propose to implement a 50% seasonal differential in demand charges.

Residential Rate Design

- We propose to modify the existing three-block rate structure into a two-block rate structure.
- We propose to set the tail block at our estimate of marginal cost for serving water heating load.

Commercial Rate Design

- We propose to separate the existing Schedule 24 into three separate schedules.

Primary or High-Voltage Rate Design

- We propose to make available an optional marginal cost rate whereby a large customer could contract to take 75% of an estimated "base" usage at a discounted rate, with all additional consumption priced at marginal cost.

FACTORS CONSIDERED IN DESIGNING RATES

Q. What information or factors did you consider in making your rate design recommendations?

A. I considered a number of sources of information and factors, including the following:

(1) the impact on integrated resource planning,

(2) results from the cost of service study,

(3) goals to be accomplished with rate design,

(4) views of interested parties, and

(5) power supply information.

Each of these is discussed in turn below.

1. Impact on Integrated Resource Planning

Q. Could you briefly describe how the goals of integrated resource planning were taken into account in developing your rate design recommendations?

A. Yes. As described in Mr. Knutsen's testimony, one of the Company's primary objectives in this filing was to design rates in a manner that facilitates implementation of our integrated resource plan. Interruptible loads have been identified in the integrated resource plan as a resource. We therefore propose in this filing to make more interruptible rate options available to our customers, and thereby increase our resource base.

Our proposals to provide a marginal cost price signal to many more customers enhances the goals of integrated resource planning by improving economic efficiency and encouraging more conservation. Our rate design proposals would give approximately 85% of our residential customers and potentially 100% of our large industrial customers a marginal cost pricing signal. Thus, fully three-fourths of our customers could be getting a marginal price signal if the concepts presented in this filing are implemented.

2. Results From Cost of Service Study

Q. How did you consider the cost of service results?

A. Results from the cost of service study were considered in a number of ways. Parity relationships from the cost of service study were used as the basis for our proposal to spread the revenue requirement across customer classes. Costs classified as customer-related costs were used as the basis for setting the basic charge. We also used the cost of service results in developing our proposal to separate the existing Schedule 24 into three new schedules.

3. Goals to Be Accomplished With Rate Design

Q. What are the objectives to be pursued through rate design?

A. Mr. Knutsen discussed a number of objectives identified in previous Commission decisions as well as those suggested by the Rate Design Task Force and the Rate Design Collaborative Group. Other objectives have been identified as well. For example, Bonbright, Danielsen and Kamerschen list a number of rate design objectives on pages 383 and 384 of their often cited book, <u>The Principles of Public Utility Rates</u>. It should be noted that some of these rate design objectives are conflicting.

Q. Which rate design objectives do you consider most important?

A. In my view, four terms seem to capture the essential rate design objectives: equity, efficiency, stability and acceptability. The term "equity" relates not only to customer equity but also to the ability of the rates to equitably cover total revenue requirement for the Company. "Efficiency" refers to the correctness of the economic price signal. "Stability," for its part, refers to both revenue and price stability. "Acceptability" captures all of the aspects of rates that make rates acceptable to customers, including simplicity, certainty and freedom from controversies. Each of these objectives is important, and must be considered alongside the others.

Q. You mentioned that some rate design objectives are conflicting. Please give an example of conflicting objectives.

A. The objectives of revenue stability, rate stability and efficiency often conflict with each other. For example, efficiency is probably best promoted through marginal cost rates, which establish what many would believe to be the correct, or efficient, price signal. However, marginal cost pricing would generally result in a revenue stream that is more sensitive to weather or economic fluctuations, and would therefore result in less revenue stability. Moreover, full implementation of marginal cost rates would also represent a major change in rate structure for many schedules.

4. Views of Interested Parties

Q. How did you take into account the views of customers and other interested parties?

A. As described in Mr. Knutsen's testimony, two groups in particular--the Rate Design Task Force and the Rate Design Collaborative Group--provided valuable information on customers' views of rate design.

Q. Did the participation of these groups produce successful results?

A. Yes. From my perspective, the exchange of ideas, viewpoints and knowledge facilitated by the participation of these groups was very useful. The numerous meetings and discussions with these groups provided the opportunity to understand more fully the competing points of view. That understanding has influenced this filing.

Q. How have you incorporated the views of the Task Force and the Collaborative Group into this filing?

A. I have included the reports of the two groups as Exhibits ____ (DWH-3) and ____ (DWH-4). In addition to these written documents, the parties to the case will be able to include their views directly in their testimony, and the Task Force members will be able to give their views during the public hearing. Although the views of the two groups were taken into account in developing our filing, the filing remains the responsibility of the Company, of course, and thus the words, arguments and proposals are ours, not the Collaborative Group's or the Task Force's. However, to the extent that the full Collaborative Group was able to endorse concepts, those concepts were included in our filing.

Q. **Are the parties to the Collaborative Group bound to support these agreed-upon concepts?**

A. Not in a strict or formal sense; there is no agreement that prohibits discussion. Instead, there is an endorsement of concepts.

5. Power Supply Information

Q. **How was power supply information used in developing your rate design recommendations?**

A. Power supply information was used in a number of respects in developing my rate design recommendations, including the following:

- the Company's avoided cost study was used to calculate marginal costs and seasonal costs,
- cost data on simple cycle and combined cycle combustion turbines and a peak energy contract with San Diego Gas & Electric was used to determine the rates for interruptible service (which information was also used by Ms. Lynch to calculate the split

between demand and energy used in the peak credit classification method), and

- information on hourly costs was used to corroborate the seasonal costs and to evaluate whether time of day costs should be reflected in rates.

Q. How did you use avoided cost information to estimate and approximate the Company's marginal energy and capacity costs?

A. The Company's most recent avoided cost study includes estimates of the costs associated with resource acquisitions contemplated under the Company's integrated resource plan. This avoided cost study is used for a number of applications, such as the Company's competitive bid solicitations, the establishment of the cost effectiveness limit in the Company's conservation tariff, and as supporting calculations for the purchased power rate for small resource acquisitions. Although this study was used as a basis for estimating marginal energy and capacity costs, limitations on the purpose of that study were recognized and adjustments made as necessary. For example, the study notes that the numbers included are for power that is generally delivered throughout the year and any significant variations from such deliveries need to be separately addressed.

Q. Will the Company be updating its avoided cost study as a result of the current competitive bid solicitation?

A. Yes. Pursuant to the Commission's competitive bidding regulations (Chapter 480-107 WAC), the Company will be updating its avoided cost schedule as a result of its most recent competitive bid solicitation. Since that update is not yet completed, the data used in this filing is based on the avoided cost in effect at the time of the most recent competitive bid solicitation.

Q. Please explain your use of power supply information to classify production costs between demand and energy.

A. As Ms. Lynch describes in her testimony, the Company used the peak credit method to classify production costs between demand and energy. This classification, of course, is not an exact science because generating and conservation resources generally perform a number of joint functions at the same time, including the delivery of energy; delivery of capacity; provision of backup for outages of other resources or transmission lines; and providing flexibility for meeting changes in hourly load.

Q. How was the peak credit factor calculated?

A. We looked at the relationship between the cost of providing base load generation and the cost of providing peaking capacity. For the cost of base load generation, the estimated cost of a combined cycle combustion turbine, as set forth in the integrated resource plan and the avoided cost filing, was used. Calculation of the cost of capacity was a bit more difficult.

Q. **How did you calculate the cost of capacity?**

A. We used the fixed cost of a simple cycle combustion turbine (CT) as the starting point for the capacity cost calculation. A simple cycle CT, however, would provide much more value than simply providing an ability to meet peak loads on the highest 200 hour loads in each year. For example, the CT could be used to back up the poor performance of other energy resources. It could also be used to help during transmission outages. Such CT's could also be used to make sales to other utilities in periods when the Company did not need them or could help provide summer resources to help accomplish seasonal exchanges, thereby effectively doubling the peaking capability of the CT. For these reasons the full fixed cost of a CT probably overstates the cost of a 200 hour per year peaking resource.

Q. **Is there an alternative measure of capacity costs?**

A. An alternative to the CT would be to use the cost of a peaking power purchase contract. Under a contract of this type, one utility pays a monthly charge to another utility for the right to purchase power during a certain time period. If the power is actually called for, then an additional payment--usually tied to the incremental cost of running a resource--is made by the purchaser. The Company recently entered into a contract with San Diego Gas & Electric to purchase such capacity for the months of November through February, and was required to pay $2/kw-mo. This kind of power may be available in the future but it is anticipated that the cost of such power would rise over time.

Q. What measure did you use for purposes of this filing?

A. For purposes of this filing we have assumed that a cost midway between the one-year capacity contract and the full fixed cost of a CT is an appropriate cost to be used for the peak credit method.

Q. How did you use power supply information to evaluate seasonal costs?

A. We looked to the Company's avoided cost data, as separated between summer and winter periods, to estimate seasonal costs. To confirm the reasonableness of the results, we looked at recent "normal" differentials in seasonal values of power. As a result of such an analysis, we concluded that a seasonal differential of approximately six mills/kwh is reasonable. This differential translates into a 10% seasonal rate differential, using a load representative of residential water heat. We incorporated this differential into our rate design recommendations.

Q. How was power supply information used to evaluate time of day costs?

A. I relied on information gathered by the Company's power supply personnel, including observations of the variation of these costs. The variation of costs within each day apparently is minimal, although the level of costs varies widely from year to year, month to month and day to day. We concluded that a reasonable estimate of the difference in time of day costs between heavy load hours and light load hours generally does not exceed four mills/kWh. As discussed later in my testimony, we concluded that an insufficient basis has been shown for offering time of day rates.

Q. How else was power supply information used in your rate decision recommendations?

A. We used power supply information to place a "value" on interruptions by analyzing the capacity costs that would be avoided, which formed the basis for the interruptible rate proposals presented later in my testimony.

GENERAL ISSUES OF RATE DESIGN THEORY

Q. What general issues of rate design theory must be addressed in this proceeding?

A. A number of general issues of rate design theory arise in this proceeding, including:

(1) the role of marginal cost,

(2) the use of elasticity estimates,

(3) how seasonal and diurnal power costs should be reflected into the price signal,

(4) the rationale for voluntary rates and the proposed evaluation process, and

(5) the use of base and resource cost data by customer classes.

Each of these is discussed in turn below.

1. Marginal Cost Pricing

Q. What is marginal cost?

A. In economic theory, marginal cost is the cost of the last unit produced. Kahn gives the following definition of marginal cost:

> [M]arginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would be saved by producing one less unit. Looked at in the first way, it may be termed incremental cost--the added cost of (a small amount of) incremental output. Observed in the second way, it is synonymous with avoidable cost--the cost that would be saved by (slightly) reducing output. (Although these three terms are often used synonymously, marginal cost, strictly speaking, refers to the additional cost of supplying a single,

infinitesimally small additional unit, while "incremental" and "avoidable" are sometimes used to refer to the average additional cost of a finite and possibly a large change in production or sales.)

Since electricity cannot be economically stored, the last unit produced is the last unit consumed. Therefore, the marginal cost of electricity is the cost of the last unit of electricity consumed.

Q. **Over what time period are marginal costs measured?**

A. Marginal costs can be either short run or long run, with long run marginal costs being those associated with the possibility of changing any or all factors that go into producing a product, while short run marginal costs assume that some costs are "fixed" and cannot be changed. An example of short run marginal cost in the electricity business would be the cost of burning a little more coal. An example of long run marginal cost would be the entire cost of building a coal plant. Short run marginal costs are somewhat analogous to variable costs.

Q. **What role does marginal cost play in rate design?**

A. The theoretical role of marginal cost is to provide the basis for efficient pricing. Marginal costs are the generally accepted mechanism used to achieve the goal of efficiency mentioned earlier. In an economist's perfect world, all customers would see a marginal price signal, and because of this all resources would be used efficiently. For reasons of economic efficiency, marginal costs should therefore be incorporated in rate design wherever practical, except to the extent they unduly conflict with the other goals of equity, stability and simplicity.

Q. Has the Commission expressed a view on the use of marginal costs in rate design?

A. The role of marginal costs has been discussed in length by the Commission in past cases. The most thorough look at this issue was conducted in 1978, when the Commission was specifically required under the Public Utility Regulatory Policies Act ("PURPA") to consider marginal costs in setting rates. The order in that case stated as follows:

> We believe that marginal costs may contain uncertain estimates and thus may not be sufficiently reliable for use in the structuring of rates; the wide disparity among so-called marginal methodologies prevents confidence in any one; the "pure" marginal theory involving taxation is utterly impractical and casts doubt upon the applications suggested, and lack of standard methods to deal with the so-called "revenue gap" problem reduce the effectiveness of marginal cost applications.
>
> Furthermore, there is no evidence to indicate that marginal cost pricing of only one commodity would develop either economic

> efficiency or engineering efficiency, and if constrained by revenue requirements, marginal costing could produce rates little different from those based upon accounting costs. Rates based on embedded or accounting costs can be forward-looking and give proper signals to ratepayers, all with a greater degree of reliability than other, less precise, theoretical methods would produce.

Commission Decision and Order, Cause No. U-78-05, p. 5.

Q. **Are these statements still valid today?**

A. Many of the arguments used in that hearing are valid today. Marginal costs are difficult to define, and are difficult to quantify. Moreover, customers may not pay any attention to marginal costs. Although these observations remain valid, we should nonetheless proceed toward more marginal cost pricing, albeit with caution, rather than not proceed at all.

Q. **Why do you believe marginal costs can be more easily implemented today?**

A. The economics of electricity production and use has changed enough that moving toward marginal cost pricing need not be as disruptive today as it would have been in 1978. Current arguments based on economic theory and the implementation of integrated resource planning are compelling. It is therefore possible to create a new balance today that includes more marginal cost pricing. The rates in this filing--which include marginal cost pricing proposals for the residential sector and the large industrial sector--would do this.

Q. How influential is the marginal cost price signal?

A. Economic literature and studies conducted by the Electric Power Research Institute generally indicate that customer demand reacts in some manner to prices, i.e., customer demand has some elasticity, although the degree of elasticity is debatable. Consumption and efficiency decisions are definitely influenced, in my view, by prices, in conjunction with strong conservation programs. Pricing and conservation programs should both give consistent signals.

Q. Which marginal costs in particular should be used in designing energy and demand rates?

A. Long run marginal production costs should be used. While production cost is not the only cost component that varies at the margin with kWh consumption, it is both the dominant cost and the easiest to quantify and comprehend. Long run costs should be used because they provide the most important price signal, particularly to the residential sector. Long-term marginal costs ideally should relate to the time period associated with major decisions being influenced, which in the residential sector are decisions regarding the consumption of energy for water heating.

Q. **Why is it appropriate to base marginal costs on water heating characteristics?**

A. One interesting aspect of the marginal cost of electricity is that **all** consumption is at the margin, not just the consumption by the appliance that uses the most electricity. It is therefore appropriate that customers who have space heat receive a marginal cost signal based on water heat usage, because these customers will also have water heat. Moreover, space heating customers need not be given a marginal cost signal based on space heat because of the persuasiveness of our conservation programs and the economics of fuel choice.

2. The Use of Elasticity Estimates

Q. **If you propose to give each customer a marginal price signal, do you need to be concerned with price elasticity?**

A. Definitely. The purpose of sending a marginal price signal is to affect consumption. If the price affects consumption, it affects receipts, which in turn will affect the Company's ability to earn allowed revenues. The goal of efficiency in yielding total revenue requirement is therefore threatened.

Q. How can price elasticity be taken into account?

A. This problem can be addressed by considering elasticity estimates whenever a major change is made to rates. Revenues that are estimated to be produced by the new rates can be adjusted to take account of expected responses to price changes. Although this adjustment has historically been controversial, decoupling should reduce the contentiousness of this issue. Under decoupling, the Company will no longer retain the benefits, nor bear the burdens, of errors in estimation.

Q. Does your filing include the use of any elasticity estimates?

A. Yes. We have incorporated elasticity effects into our calculation of the impact of the proposed power factor cost.

3. Seasonal and Diurnal Power Costs

Q. How do seasonal swings in power costs affect rate design?

A. As was mentioned earlier, the differential between summer and winter is about 10% for energy costs, which should be reflected in seasonal differentials for energy rates. In addition, the Company's peak is seasonal as well, and demand charges ideally should reflect this seasonality. As discussed more fully in "Other Rate Design Proposals," the Company proposes to introduce a seasonal differential to demand charges under certain schedules.

Q. Do you propose to reflect variations in power costs by time of day in your rate design proposals?

A. No. These variations are small in relation to the cost of metering time of use consumption. We therefore propose to wait until the next generation of metering and billing system is in place, when these metering costs presumably will be lower. Accordingly, time of use rates are not included in this filing.

4. Voluntary Rates and the Evaluation Process

Q. Why are you recommending some rates to be voluntary?

A. Interruptible rates are traditionally voluntary, primarily because of obligation to serve issues. The large power marginal cost rates--Schedules 30 and 48--for their part, are voluntary because they are experimental. With experimental rates we have the chance to gain experience in terms of customer acceptance, resource impact and the capability of the Company to administer the rate. We can also minimize any revenue impact by restricting access.

Q. How will you evaluate the success of voluntary rates?

A. We plan to evaluate the effectiveness of our rate experiments by once again asking for assistance from those who helped us explore the issues behind rate design, rate spread and cost of service. We will be forming an Experimental Rate Design group to help us evaluate our rate experiments.

5. Base and Resource Cost Data

Q. Please discuss your concerns regarding the use of base and resource costs for the Company's customer classes.

A. In the Decoupling Proceeding, the Commission ordered the Company to provide in the next case "data sufficient to determine the base and resource cost for each of the Company's customer classes." (Third Supplemental Order, p. 25.) Our filing includes this information as a scenario in Exhibit ___ (CEL-5). ~~This data would permit the assignment of a different base cost to different customer classes, if this assignment were deemed appropriate. However, such an assignment would be highly inappropriate, in my view.~~

~~**Q. Why would such an assignment be inappropriate?**~~

~~A. It would misconstrue the purpose of the cost per customer calculation in the decoupling process. The purpose of the cost per customer calculation is to provide a proxy for changes in costs between general rate cases that is at least as good as the proxy~~

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provided by kWhs. It was never intended to be representative of **specific** costs of **specific** customers.

Q. What would be the problem of having a different base cost per customer for each customer class?

A. There would be a number of problems. **First,** it would create more instability in base revenues. These revenues would be dependent on the mix of customers, instead of general customer growth. The addition or deletion of only one industrial customer, for example, could produce a revenue swing of as much as a million dollars. **Second,** it would create a mismatch of costs and revenues. The costs that these revenues represent are not dependent to any significant extent on the mix of customers at the margin. **Third,** it would create a perverse incentive. The Company could get more revenue by attracting large customers, or by trying to convert customers from a low-voltage service to a high-voltage service.

RATE SPREAD PROPOSAL

Q. Please describe how parity relationships were used to develop the Company's rate spread proposal in this proceeding.

A. Parity is the relationship between what customers should pay according to a cost of service analysis and what the customers are actually paying. A parity relationship of

90%, for example, means that a particular customer class is paying only 90% of the costs allocated to it. This also means that the customer class is being subsidized by other customers. If one class of customers is below parity, and thus enjoying a subsidy, another class must be above parity and paying the subsidy, because parity based on the allowed revenue requirement must, by definition, average 100%.

Q. What parity relationships are shown by the results of your cost of service study?

A. The results suggested by the proposed cost of service study indicate the following parity ratios:

Residential	Secondary	Primary	High Voltage	Lighting	Resale
.93	1.25	.95	.83	1.10	.96

Q. Based on these findings, how do you propose to allocate the revenue requirement across classes, or spread rates, in this proceeding?

A. We propose to spread rates in a manner that moves toward 100% parity for all classes. In the interests of gradualism and rate stability, we propose to move only one-third of the distance to the target parity in this filing, and to use an "equal percentage of difference" approach in implementing this proposal. Under this approach, the amount of subsidy received or paid by a class is reduced by an equal percentage.

Q. What is the impact of this approach in this filing?

A. Our cost of service study shows that residential and high voltage customers are currently receiving subsidies of $31.5 million and $14.3 million, respectively. These subsidies are being paid primarily by general service (commercial) customers, who are currently paying $47.6 million in excess of their indicated cost of service. Our proposal would reduce these cost subsidies by one-third. Specifically, we propose to increase the revenue responsibility assigned to the residential and high voltage classes by $10.5 million and $4.8 million, respectively, and to decrease the revenue responsibility assigned to the secondary general service class (commercial) by $15.7 million. Other classes would be adjusted as well so as to leave the total revenue requirement unchanged.

Q. What rate increases or decreases result from this proposed reduction of cross subsidies?

A. The approach described above results in the following percentage changes to base rate in each class:

• Residential	-- Plus 2.4%
• Secondary General Service (commercial)	-- Minus 6.6%
Schedule 24	-- Minus 4.7%
Schedule 25	-- Minus 9.8%
Schedule 26	-- Minus 3.9%
• Primary	-- Plus 1.7%
• High Voltage	-- Plus 6.7%
• Lighting	-- Minus 2.9%
• Resale	-- Plus 1.6%
• Total System	-- No change

Q. How does this proposed rate spread change the parity relationships?

A. This rate spread proposal would produce the following parity ratios:

Residential	Secondary	Primary	High Voltage	Lighting	Resale
.96	1.17	.97	.89	1.06	.97

RATE DESIGN PROPOSALS

Q. What are the rate design proposals included in the Company's filing?

A. The Company's filing includes rate design proposals in the following five general categories:

(1) residential rate design;

(2) general service rate design;

(3) primary/high voltage rate design, including an experimental marginal cost based rate;

(4) various other rate design proposals, including interruptible rates for large power customers, a proposed power factor adjustment, an increase in the seasonal differential for energy charges, and a differential for seasonality in demand charges; and

(5) the allocation of PRAM revenues.

1. Residential Rate Design

A. Issues

Q. What issues with respect to residential rate design were identified by the Company and interested parties?

A. Review of the current residential rate design by the Collaborative Group and the Task Force highlighted five major issues for the Company:

- the appropriate level for the basic charge,
- the importance of the inverted block structure to encouraging conservation,
- sending a marginal cost price signal to more of our residential customers,
- the possibility of special interruptible or time-of-use rates, and
- the possible use of special hookup charges to further encourage energy efficiency in new residential design.

Q. What is involved in the issue regarding the basic charge and inverted rates?

A. Determination of the appropriate level for the basic charge was a contentious issue that highlighted different perceptions about what is viewed as equitable and how to balance equity with economic efficiency. Both the Company and the Task Force concluded that there are significant fixed costs in the distribution system that are best reflected under a minimum system type approach. Proponents of this approach cite equity as the major concern. A group of captive space heat customers may end up subsidizing other customers through the current recovery method for much of the distribution system costs. Those arguing against a high basic charge, on the other hand, cited economic efficiency grounds. In order to encourage conservation, the costs arguably should be concentrated on the energy charges, the more elastic portions of the customer's bill.

Q. **Did the Collaborative Group reach a consensus on this issue?**

A. The Collaborative Group agreed to abide by the Commission's decision in the Company's 1989 rate proceeding (Docket No. U-89-2688-T) and to use the basic customer definition that includes the fully loaded meter, service drop, meter reading, and billing costs. A more complete discussion of this approach is set forth in Ms. Lynch's testimony.

Q. **What method are you proposing to provide a marginal cost price signal in the residential sector?**

A. The Company is proposing that the Commission adopt a two block inverted rate schedule rather than the current three block inverted rate. Our goal is to set the tail block at or near marginal costs, either in the next general rate case or in subsequent PRAM filings. The two block rate has the advantage that about 85% of our residential customers will receive a marginal cost price signal.

Q. Does the two block rate mean that there are no differences in costs serving customers with different load factors?

A. No. Clearly, space heat customers have a somewhat different marginal cost than water heat customers. One problem is the marginal block for some space heat customers, such as those in apartments, is relatively low, while the marginal block for others, such as those in large single family homes, is quite high. We have never been able to assure ourselves that those whose marginal consumption fell in the 600 to 1,000 block were only water heat customers. Another more basic problem is that the consumption of **all** appliances is at the margin. Therefore, even if a space heat customer registers consumption in the over 1,000 kWh block, that block represents the marginal cost for all appliance, including lights. The rate design goals of efficiency and simplicity are better met with a two block structure than a three block structure.

Q. Did you evaluate time of use and interruptible rates for the residential sector?

A. Both options were considered, as described earlier in my testimony. Time of use rates were rejected as not being appropriate at this time. On the other hand, we are recommending adoption of an experimental interruptible water heat rate.

Q. **Please explain why you feel that an interruptible water heater rate is appropriate.**

A. Both the Collaborative Group and the Task Force concluded that residential customers should participate in and benefit from interruptible rates.

Q. **Why are you proposing the water heater interruptible rate on an experimental basis?**

A. There are a number of issues that still need to be addressed. These issues include: the best way to signal the interruption, the impacts on the local distribution system following an interruption, and customer acceptance. Inasmuch as the value to the system at this time is marginal but undoubtedly growing, we feel this is a good time to get our program underway on an experimental basis.

Q. **Did the Company consider hookup charges as a mechanism to encourage energy efficient new residential housing?**

A. Yes, the Company considered hookup charges for site-built and manufactured housing at the request of some members of the Collaborative Group. In conjunction with the Conservation Technical Collaborative Group, the Company determined that the current energy code already incorporates measures that are cost-effective from the Company's perspective. Moreover, a number of developments are expected to occur during the coming months, which suggest that no action be taken now. The Company, together with others throughout the region, initiated the regional manufactured housing assistance program. Negotiations with manufacturers are underway regarding "phase out" periods for units in inventory. Other practicalities of the program's operation are expected to evolve during the coming months. These activities and other issues of concern to the Company were not discussed in detail during the collaborative process. The Company will therefore be discussing this issue more thoroughly with the Conservation Technical Collaborative Group before making any recommendations on hook-up fees.

Q. Did you consider low-income rates?

A. Yes, we did. Low-income rates were discussed in depth by both the Collaborative Group and the Task Force. The Task Force recommended against these rates, and the Collaborative Group did not endorse them as a concept. However, there was strong support from elements of both groups for some action that addressed the problems of low income. The Company is not proposing any action at this time, but expects other parties in this proceeding may make proposals in this regard.

B. Specific Proposals

Q. Please provide a general description of your proposed residential rate design.

A. As proposed by the Collaborative Group, the residential rate includes a monthly charge based upon the basic customer approach and a two block inverted energy rate. The proposed rate, based upon the pro forma revenue requirement from the 1989 rate proceeding (Docket No. U-89-2688-T), is shown in Exhibit ___ (DWH-5). As part of residential rate design, we also propose to introduce an interruptible water heater rate on an experimental basis.

Q. Please explain how the basic charge of $4.75, shown in Exhibit ___ (DWH-5), was computed.

A. The basis is shown in Exhibit ___ (DWH-6) using the cost of service information presented by Ms. Lynch. It includes the fully allocated cost of the meter, service drop, meter reading, and customer billing.

Q. What was the reason for changing the block structure?

A. The first block was lowered from the current 600 kWhs a month during both summer and winter months to 400 kWhs a month during the summer season and 500 kWhs during the winter season in order to increase--to 85%--the proportion of customers who receive a marginal cost price signal in the tail block. According to my estimates, only 74% of the customer bills would have been in the tail block had it been left at 600 kWh.

Q. **How was the energy rate for the tail block determined?**

A. As discussed earlier, the energy rate for the second block, or tail block, ideally should be set to reflect marginal costs in order to achieve the rate objective of efficiency. However, this objective conflicts with the goal of stability, in terms both of historical rate stability or gradualism and of the stability of the Company's receipts. The higher the tail block rate, the lower the first block rate (assuming a fixed revenue requirement). Both of these changes would make the collection of revenues less stable. I therefore recommend that the tail block energy rate be set at marginal cost for purposes of this proceeding, subject to modification, if necessary, in the general rate case if subsequent information indicates a change in costs.

Q. **What is your current estimate of the marginal costs to be reflected in the residential tail block?**

A. A rate of $0.061/kWh is used for the winter and $0.055/kWh for the summer. These rates reflect the seasonal avoided production cost to serve, over a 12-year period, a load with the general characteristics of water heat, after taking into account the impacts of Schedule 100 (PRAM) and Schedule 94 (residential exchange). As described earlier, a water heat avoided cost was used because it represents a predominant portion of the residential load and is relatively sensitive to pricing signals. It should be noted that the above rates reflect full marginal costs. If a more gradual movement toward marginal costs is desired, the tail block could be set at some proportion of marginal costs, with full implementation to follow by applying PRAM increases to the tail block. Once the tail block has been set at full marginal costs, of course, further increases should be applied to the first block.

Q. How was the first block energy rate of $0.04241/kWh set?

A. The first block rate was set by subtracting the revenues that are projected to be recovered in the tail block from the total revenue requirement assigned to the residential class under the cost of service study (Exhibit ___ (CEL-3). The revenue expected to be recovered in the tail block was determined by multiplying the rate discussed above times the number of kWhs expected to be consumed in that block. The revenue that remained after the subtraction was divided by the number of kWhs projected to be consumed in the first block.

Q. **What would be the rate impacts on residential customers if the illustrative rates were implemented?**

A. The rate impacts are shown in Exhibit ___ (DWH-7). Even though the revenue requirement for the class as a whole increases by 2.4%, one-third of the residential customers would see a decrease in their bills, with some very large users seeing a decrease of over 5%. Most residential customers would experience very little change, while large users would see an increase. Fewer alh than ~~11%~~ 1% of residential customers would have an increase of more than 5%.

Q. **What is the purpose of the experimental water heater rate?**

A. There are three main objectives for the experimental rate. They are:

- to evaluate the benefits of interruptible water heaters to the Company as a peak load "resource,"
- to evaluate customer acceptance of the rate, and
- to gain operational experience with the equipment.

Based upon these objectives, the experimental water heater interruptible rate shown in Exhibit ___ (DWH-5) was developed.

Q. Will the availability of this experimental rate be limited?

A. Yes. The availability will be consistent with the experimental nature of the rate. It is premature to make an extensive investment in equipment without a field test. The restrictions will relate to the definition of the "field" for the experiment. The rate will be offered in a single geographic area which will be determined by the Company, and will be offered to a limited number of customers.

Q. How will the rate work?

A. The customer will be offered a monthly discount of $5.35 in return for the Company's right to interrupt the customer's water heater during the hours of 5:00 a.m. to 11:00 p.m. The Company will have the right to interrupt the water heater for up to 4 hours per interruption with a maximum of 2 interruptions per day.

Q. Will the customer be allowed to override the water heater interruption?

A. No. If the customer has the ability to override the interruption then the value of this device as an alternative to a peak resource is seriously compromised. This is to be a "firm" interruptible resource.

Q. Why is the customer required to remain on the program for five years?

A. The five-year provision is designed to allow the Company to recover the cost of the installation. In addition, in order to the justify the proposed credit on a cost basis, the characteristics of the alternative must compare with those of other firm resources. These resources generally have a life which extends at least several years.

Q. When will the rate be offered?

A. The Company is currently designing the experiment and evaluating interruption technologies. We propose to begin offering service under the experimental tariff within six months after it is approved by the Commission.

Q. Is a limited test necessary given that interruptible water heater rates are used by a number of utilities?

A. A limited test is advisable due to rapid changes in equipment technology, localized communications issues, and Company-specific operations.

Q. How was the interruption credit determined?

A. The $5.35/month credit is based on an analysis of cost effectiveness performed by the Company. The calculation of this credit is shown in Exhibit ___ (DWH-8).

C. Summary of Recommendations

Q. Can you summarize the Company's recommendation for the residential rate design?

A. Yes. The Company recommends that:

- a seasonal price differential in the tail block should be maintained to reflect market conditions,
- the Commission adopt the proposed inverted two block rate design with the customer charge based on the basic customer method, and
- an interruptible water heating rate should be approved on an experimental basis.

2. General Service Rate Design

A. Issues

Q. Please describe the issues concerning rate design for commercial general service secondary voltage.

A. Many of the concerns identified by the Company and the Collaborative Group were similar to the residential rate design. Four major concerns are as follows:

- how to equitably treat this group of customers given the large divergence in energy consumption and load factors,
- how to provide a marginal cost price signal,
- how to allow this class of customers to participate in interruptible rates, and
- how to provide the correct price signal for customers with reactive power requirements.

The latter two issues are common with other non-residential customer classes, and are discussed in "Other Rate Design Proposals" below.

Q. Please explain the diversity of energy and demand use in the existing general service class.

A. The current general service rate class includes a diverse group of customers ranging from the small "mom & pop" store to the high rise office building or manufacturing building. Over 20% of these customers have average monthly consumption of less than 500 kWh/month.

The remaining customers are demand metered and in some cases metered for reactive power. Approximately 6% have annual peak demands in the range of 50-350 kW and only 0.5%, or 400, of the customers have monthly peak demands above 350 kW. The large demand customers--monthly demands over 350 kW--are similar to our primary voltage customers except for their service voltage and the associated transformation costs and energy losses. As testified to by Ms. Lynch, these three customer classes have distinctive metering requirements and load profiles with associated cost implications. For equity reasons, we are proposing that they be separated into three distinct rate schedules.

Q. Are you proposing a marginal cost rate for any of the non-residential secondary voltage service customers?

A. No. Although we studied extensively the possibility of developing a marginal cost rate for the group of customers with the smallest demand levels, we found that even within this group the diversity was too great to accommodate a marginal cost rate. The challenge is even greater for the two groups with higher demand levels. We are hopeful that the proposed experimental marginal cost rate for large power customers may provide a basis in the future for developing marginal cost rates for these customer groups.

Q. Please explain the basis for your proposal to reflect seasonality in demand charges.

A. As Ms. Lynch testified, the cost of service study identifies a number of components that constitute the cost basis for the demand charge. These components include: power generation costs, transmission, and distribution costs. The peak distribution costs are essentially the same regardless of when they occur. Therefore, these costs would be recovered equally over all months. On the other hand, if the customer's peak demand is not coincident with the system peak's demand, then that customer does not cause the need for peak load generation. Consequently, it is argued that the peak demand costs should only be recovered from loads occurring in the likely peak periods. Differences in seasonal demands can be priced either with seasonally differentiated demand charges or seasonal demand ratchets. This filing uses both of these approaches, as discussed later in my testimony.

B. Specific Proposals

Q. Please summarize the changes to the nonresidential general service rate schedule.

A. We propose to separate the nonresidential general service rate, the current Schedule 24, into three schedules:

- customers with an estimated peak monthly demand of less than 50 kW (these customers generally would not have a demand meter);
- demand metered customers with an estimated peak monthly demand between 50 kW and 350 kW; and
- customers with an estimated peak monthly demand of greater than 350 kW.

Each of these schedules is proposed to have seasonalized energy rates. In addition, Schedules 25 and 26 would have seasonalized demand charges. Rates for these three proposed schedules are provided in Exhibit ___ (DWH-5).

Q. Please review the cost differences among the proposed three general service rate classes.

A. Starting with the basic charge components, Exhibit ___ (DWH-5) shows two different basic charges. The difference in the basic charge is primarily due to differences in metering cost. The two larger groups require demand meters. The second major cost difference is the allocation of demand costs. Load research data found in Exhibit ___ (CEL-2) show the coincident demands and non-coincident load factors of each of the three rate classes.

Q. What criteria will be used to qualify a non-residential customer for one of the three general service rates?

A. For new customers, we will estimate the customer's demand. If the estimated demand is less than 50 kW, we will place the customer on Rate Schedule 24. This estimating procedure is the same as the procedure in use today to determine whether a customer will be charged the demand charge under the existing tariff. If the estimated demand is greater than 50 kW we will use actual metered demand to determine the appropriate schedule. The average of the two maximum demands measured (or the estimated maximum demand in the absence of metering) in the last 12 months will be used to determine the correct general service rate schedule. In addition, a customer will not be allowed to change the general service rate schedule for the metered service more than once a year.

Q. Please describe the rate for proposed new Schedule 24.

A. Each customer will pay a basic customer charge of $4.75 (single phase) each month. This customer charge was developed using the customer-related costs allocated to this class in Ms. Lynch's testimony. Exhibit ___ (DWH-6) shows this calculation. Seasonalized energy charges under Schedule 24 are $0.04694/kWh during summer months and $0.05163/kWh during winter months. These charges were calculated simply by dividing the class revenue requirement by kWhs and applying the seasonal differential.

Q. What is the effect of this rate on customers?

A. The effect is shown in Exhibit ___ (DWH-7). Eighty-four percent of the customers will receive a decrease in their bills, with 8% having decreases greater than 15%. Fewer than 1% of the customers will have an increase in excess 5%. The average charge for all customers under the schedule is a decrease of about 5%.

Q. Please describe the proposed Schedule 25 rate.

A. This schedule is similar to the existing Schedule 24 Rate, except that Schedule 25 has two energy blocks.

The customer charge for Schedule 25 is increased to reflect the customer costs allocated to this sector under the cost of service model. The demand charges apply to all demands over 50 kW. The demand charge is seasonalized, with a 50% differential between the summer demand rate and the winter demand rate.

Q. **How were the energy charges under Schedule 25 determined?**

A. The first block rate was decreased by 10% to reflect the overall decrease in revenue requirements assigned to this schedule. The remainder of the target revenue requirement was divided by the kWhs consumed in the tail block, then adjusted to achieve a 10% differential between winter and summer. The basis for these calculations is found in Exhibit ___ (DWH-6).

Q. **What is the effect of this rate on customers?**

A. The effect of this rate on customers is shown in Exhibit ___ (DWH-7). Over 98% of the customers will receive a decrease in their bills, with almost 30% having reductions in excess of 10%.

Q. **Please describe the proposed Schedule 26 rate.**

A. This schedule is similar to Schedule 25 except that the energy rate is not separated into blocks and demand charges apply to all metered demand. The seasonal energy rates of $0.0333/kWh in winter and $0.03028/kWh in summer were set by dividing the energy costs allocated to this class under the cost of service study by the number of kWhs this class used during the test year. The demand charge is similarly derived by dividing the demand costs allocated to the class in the cost of service study by the demand metered during the test year, with an adjustment for the impacts of the power factor adjustment.

Q. **What is the effect of this rate on customers?**

A. The effect of this rate on customers is shown in Exhibit ___ (DWH-7). Seventy-four percent of the customers will receive a decrease in their bills, with over 10% of the decreases being greater than 10%. Of the 26% of the customers receiving an increase, fewer than 2% will have an increase greater than 10%.

Q. **Please describe the proposed Schedule 29 rate.**

A. Schedule 29, Season Irrigation and Drainage Pumping Service, has historically had rates that are less than under the general service schedule, Schedule 24, due to the advantageous seasonal nature of the load. The existing rate advantage for Schedule 29 is roughly equivalent to the excess over parity which our cost of service study suggests is currently being paid by the be willing and prepared to be interrupted any time that the Company's power supply economics dictate that the interruption should occur. The value of the five-year interruption agreement was set one-fourth of the way between the one-year and 30-year value.

Q. What is the notification procedure and the associated costs?

A. The Company proposes that each customer would be notified though a dedicated computer and printer on the customer's site. The customer would be responsible for providing a direct phone line to the computer and wiring necessary to connect the computer to the customer's alarm and notification systems. The Company would transmit the interruption request via electronic mail.

Q. Would you please explain the credit paid for each interruption?

A. Yes. A customer who complies with the Company's interruption request results in saving the Company a marginal fuel expense and either a marginal wheeling expense in the event of a contract or a marginal O&M expense if the Company-owned generation is used. This savings is diminished by an incremental expenses for collecting customer load data. The Company also made an adjustment for lost revenues.

known and measurable changes. Some fraction of the historic consumption, 25% for example, could be designated as the tail block and priced at marginal cost. The remaining consumption would be at a lower rate such that the weighted average of the two blocks recovers the average energy and demand cost allocations of the class.

Q. **Does your proposed blocking scheme create any potential problems?**

A. Yes. One problem arises from variations in consumption over time. For example, an analysis of historic billing information for almost all of our primary and high-voltage customers indicates that on a customer-by-customer basis over 20% have energy use in the fifth year that varies from the average of their four prior years consumption by over 20%. To accommodate this variation, we propose to include an adjustment mechanism associated with using the historic bills to set the block.

Q. **What types of adjustments do you envision?**

A. Any adjustment mechanism that relies on judgment rather than strict quantitative measurements can be expected to be controversial. Nevertheless, adjustments are probably necessary for physical changes in the customer's productive facilities and to reflect installation of conservation measures financed by the Company.

Q. **What are the benefits of creating a marginal cost rate?**

A. The primary benefit is that it promotes economic efficiency at the facility and thereby promotes the goals of integrated resource planning and encourages conservation. The customer is given the correct price signal to conserve inasmuch as the savings associated with energy in the tail block is priced at marginal cost. If the customer decides to increase consumption, the customer will therefore pay the full cost of the expansion. The proposed rate design is also equitable because (1) the customer would see no change in its bill with no change in consumption and (2) the rate in its current form is proposed as experimental and voluntary.

4. Other Rate Design Proposals

a. Interruptible Rates for Large Users

Q. **What types of interruptible rates are you proposing for large users?**

A. Two types of rates were discussed by the Collaborative Group: a rate where the customer commits to an interruption as defined in a contract, and a voluntary rate where the customer can curtail and receive a credit but faces no penalty for not curtailing load. More generally, there was an interest by all parties to modify and expand the interruptible rate option to attract and qualify more customers for the rate.

Q. **Please review the current status of interruptible rates.**

A. The Company currently has two interruptible rate schedules: Schedule 46 applies to high-voltage customers, and Schedule 43 applies to all electric schools served at primary voltage. Schedule 46 customers can be interrupted during the morning or evening peak periods, while Schedule 43 customers can be interrupted during the evening peak period. Customers under Schedule 43 must reduce their load to 0.6 watts/square foot or face demand charge penalties.

Q. **What additional interruptible rate options does the Company propose to make available?**

A. The following changes are proposed:

- all customers who are willing to commit to reducing their load by 300 kW during an interruption period will qualify for an interruptible rate,
- interruption contracts will be available for one and five years,
- the reduction in demand charges will be a function of the amount of load interrupted and the length of the interruption contract,
- there will be penalties for failing to interrupt, and

- the current Schedules 43 and 46 will be closed to new customers.

Q. What do you propose for those customers currently taking service under interruptible rate schedules?

A. The new rates are meant to be more general and more flexible than the existing rates, and therefore should be preferred by our current interruptible customers. However, in specific instances they might not be. Customers on existing Schedules 43 and 46 will therefore be allowed to decide which rate they prefer, and for those customers who remain on existing schedules, the current relationships between the demand charges for Schedule 31 versus Schedule 43 and Schedule 46 versus Schedule 49 will be maintained in all future rate changes. Schedules 43 and 46 will not be available to new customers upon approval of the proposals offered here.

(i) Interruptible Service Credit--Firm

Q. What is the purpose of the interruptible service credit for firm power?

A. The objective is to extend an interruption option to more customers so the potential for interruption resources in our integrated resource plan can be increased. Interruptions provide an alternative to peak generating resources.

Q. What is the value of firm commitments by customers to interrupt load during peak load periods?

A. The value is the potential delay or avoidance of acquiring peak load resources for the needle peak hours. All customers are better off if the customer credit for interruption is less than the cost of acquiring a peak resource (after adjustment to reflect customer notification and other administrative costs).

Q. Please describe the proposed credit.

A. The Company is proposing three riders--36, 38, and 39--that would apply to Schedules 26, 31, and 49. These riders, shown in Exhibit ___ (DWH-5), contain three classifications based on the expectation of the duration of the curtailment period and the frequency of the duration. These three classifications are:

- long-term firm
- short-term firm
- non-firm.

The non-firm classification is discussed in the next section of my testimony.

Q. Could you please explain the two proposed firm classifications?

A. Yes. Each of the firm classifications has two components. The first component is a monthly credit applied to billable demand that is in excess of the customer's contracted firm kW demands. Second, a credit is paid for each interruption based upon the value of the imputed kWh above the firm demand level not consumed, less verification costs.

Q. **How is the customer's firm kW demand established?**

A. Each customer would define a firm demand level for the winter months of November-February. In the event of an interruption call from the Company, the customer would be required to reduce its maximum demand during the interruption period to at least its firm demand level. Each schedule specifies a requirement for the firm demand level in terms of its relationship to the customer's average monthly winter demand and a minimum absolute demand. The Company established this restriction because it is concerned about having to work with too many customers prior to the testing and evaluation of this rate. Demand charges in excess of the customer's firm demand treated during the November-February period are treated by charging the excess demand (the non-firm demand) at the normal demand rate less the monthly demand credit.

Q. **Would you please explain the basis for valuing the monthly demand credit?**

A. Two different credits are used in the rates: One credit is for the one-year contract (short-term) and the other credit is for the five-year contract (long-term). The short-term credit of $0.75/month and the long-term credit of $1.25/month is based upon the annualized fixed cost that the Company avoids by utilizing interruptible contracts. The customer credit is the sum of the avoided capacity cost less the fixed interruption notification costs. The avoided capacity credit, based upon the length of the interruption contract, is derived from the Company's avoided capacity cost. The fixed notification cost is based upon the proposed notification procedure.

Q. How was the value of interruption determined?

A. The value to the Company of an interruption agreement needs to reflect the number of years the customer would commit to participate. For example, if the customer only agrees to be interruptible for one year at a time, then it would be appropriate to use a value that relates to our current contract with San Diego Gas & Electric, which is $2/kw-mo for 4 months. If the customer agrees to a 30-year interruptible arrangement, then half the fixed cost of a combustion turbine is more appropriate (reflecting that the CT provides benefits beyond the winter peak). In both cases, this would need to be a "firm" interruptible contract, i.e., the customer must be willing and prepared to be interrupted any time that the Company's power supply economics dictate that the interruption should occur. The value of the five-year interruption agreement was set one-fourth of the way between the five-year and 20-year value.

Q. What is the notification procedure and the associated costs?

A. The Company proposes that each customer would be notified though a dedicated computer and printer on the customer's site. The customer would be responsible for providing a direct phone line to the computer and wiring necessary to connect the computer to the customer's alarm and notification systems. The Company would transmit the interruption request via electronic mail.

Q. Would you please explain the credit paid for each interruption?

A. Yes. A customer who complies with the Company's interruption request results in saving the Company a marginal fuel expense and either a marginal wheeling expense in the event of a contract or a marginal O&M expense if the Company-owned generation is used. This savings is diminished by an incremental expenses for collecting customer load data. The Company also made an adjustment for lost revenues.

Q. How is the energy credit calculated?

A. Calculation of the energy credit is described in the riders. The procedure is designed to predict the customer's consumption in the absence of the curtailment. This prediction is done by either using similar days in the prior thirty-day period or using linear interpolation between the period one hour prior to the curtailment to two hours after the curtailment.

Once the energy use has been predicted, the energy credit is calculated as the difference between the predicted energy use during the curtailment period and the customer's firm demand level multiplied by the duration of the curtailment. A credit is paid if the resulting value is positive and the customer reduces demand to at least the firm demand level.

Q. How will the Company determine if the customer has curtailed load to the firm level specified by the contract?

A. The Company will read 15-minute demand data recorded at the customer's site. The maximum demand during the interruption period will be compared to the customer's contracted firm demand. A metered demand in excess of the contracted firm demand will constitute a contract violation. If there is a contract violation, the customer will be charged an excess demand penalty (shown in Exhibit ___ (DWH-5)) based upon the difference between the metered demand and firm demand level and will receive no energy reduction credit. The basis for the penalty is to make sure that a customer who has received the credit but fails to interrupt is not better off than similar customers on non-interruptible rates. If the customer fails to interrupt more than once, then the penalty increases.

Q. **How did you determine the maximum number of interruptions, the maximum duration of the interruptions, the notification period, the maximum number of customers and the maximum total estimated demand reductions.**

A. This was done in consultation with power supply personnel. These parameters were set so the interruptions would most effectively fit with power supply operations. The restrictions on the number of customers and estimated demand were imposed because of the experimental nature of the rate. The Company would like to gain experience with the notification procedure, effectiveness, and customer acceptance before the rate becomes permanent.

(ii) Interruptible Service Credit--Non-Firm

Q. Please describe this rate and explain how it is different from the firm interruptible rate.

A. Under the non-firm rate, the customer decides whether to interrupt service in response to the Company's request. Since the customer under the voluntary rate does not agree to interrupt at our bidding, it is not a "firm" resource. Accordingly, customers would be compensated only if and when they actually interrupt their service at the Company's request. The firm rate, in contrast, gives customers a credit year around in exchange for the right for the Company to interrupt at the Company's discretion.

Q. How did you calculate the rate?

A. We reduced the value of the firm interruptible rate by a "non-firm" factor. This factor is based on a reasonable expectation of the number of customers that will actually interrupt when asked. We are estimating this factor to be 50% of the value of the one-year contract for purposes of this filing.

b. Proposed Power Factor Adjustment

Q. Why is the Company addressing the charges for poor power factors in this filing?

A. This issue was raised by members of the Collaborative Group and the Task Force. There has been some concern that the current charges imposed on customers with poor power factors are too low. This rate design proceeding provides a good opportunity to look at the entire issue of reactive power and its impacts on the Company's system.

Q. How does the Company currently charge for poor power factors?

A. The Company currently has a reactive power charge denominated by a Killovar hour, or kVarH, that is charged to all secondary and primary voltage customers with over 100 kWs of demand. High-voltage customers see this adjustment in their kVa charge.

Q. What issues associated with reactive power did the Company identify?

A. The Company has three concerns:

- the system impacts of customers with reactive power requirements,
- the best way to measure these reactive power requirements, and
- whether the costs recovered are in the current var-hour charges.

Q. Could you briefly describe the system impacts of customer reactive power requirements?

A. Yes. Reactive power requirements create a requirement on the system that is not measured with kWh meters. This additional requirement, if uncorrected, may require the need to increase the capacity of distribution and substation transformers, distribution and transmission conductors, and increase generation requirements. Another impact is that supplying customer reactive power requirements can increase system losses associated with the larger kVa requirements.

Q. What schedules would be affected by your power factor adjustment proposal?

A. This proposal would apply to Schedules 25, 26, 29, 31, 35, and 43. It would not apply to the high-voltage Schedules 46 and 49 because the demand meters used are capable of metering kVa directly, which is a preferred method of measuring poor power factors.

Q. What is the alternative method that you are proposing?

A. The customer's power factor would be used to adjust the metered demand. The calculation, shown in the tariff sheet in Exhibit ___ (DWH-5), essentially produces the effect of a kVa charge for customers with power factors below .95.

Q. Why is the rate designed to produce the effect of a kVa charge?

A. As I testified previously, kVa is considered to be reflective of the actual cost to the Company of serving the extra load and supplying the extra energy losses associated with reactive power requirements.

Q. Do any other utilities charge for power factor this way?

A. Snohomish PUD, Tacoma City Light, and Idaho Power adjust metered demand by the customer's power factor. The utilities have different base levels ranging from 0.85-0.95 power factors and slightly different ways for adjusting for the power factor. For example, Tacoma City Light multiplies the metered demand by 0.95 and divides by the average power factor.

Q. What are the rate impacts associated with the proposed power factor adjustment?

A. Customers with a power factor of 95% or above would see a decrease in their rates from the effect of the power factor adjustment. Customers with poor power factors would see an increase, while the average customer would see very little change. The average change for Schedule 31 customers is an increase of about 3%, while secondary customers (Schedules 25 and 26) would see an increase of about 2%.

c. Seasonality in Demand Charges

Q. How do you propose to add seasonality into your demand charges?

A. At the outset, it should be noted that our high-voltage schedule already includes seasonality through the 100% demand ratchet for peak demands which occur during the winter. Schedule 31, for its part, uses a 60% ratchet.

In addition to these demand ratchets, we propose to add seasonal demand charges to Schedules 25, 26, 29, 31, 35 and 43.

Q. **Please explain how the demand ratchet provides a seasonality charge.**

A. A Schedule 49 (High Voltage) customer currently is charged a minimum of $2.80 per month times 12 months, or $33.60 a year, for a peak demand which occurs during the winter season. For a peak demand occurring in the summer months, on the other hand, a customer would be charged only $2.80 times one month, or $2.80. This ratchet mechanism provides a substantial incentive for customers to reduce winter peak loads.

Q. **How do you propose to reflect seasonality in the demand charges under other schedules?**

A. An alternative approach to the demand ratchet is a monthly demand rate which varies by season. We propose to institute a seasonal differential for rates in other demands-metered schedules by applying a 50% differential to demand charges. The advantage of this type of seasonal differential is that it is easy to understand and it gives a price signal throughout the year.

5. Allocation of PRAM Revenues

Q. How does the Company propose to allocate PRAM revenues to each class of customers?

A. The same way that was approved in the Decoupling Proceeding, with the exception that irrigation customers should receive an appropriate share of the adjustment.

Q. How should the rates be spread to the demand, energy and customer charges once they are spread to each customer class?

A. Again, the same way as was approved in the Decoupling Proceeding, with one exception. All of the charges spread to the residential class should first be applied to the tail block rate until that rate reaches 100% of the marginal cost defined above. The remainder would be added to the first block rate.

Q. Are PRAM period revenues of separate customer classes considered in the allocation of costs or revenue shortfalls to classes of customers?

Q. No. If we were to track over or under collection of PRAM period revenues by class of customers and assign these over or under collections only to that customer class, this would assign a preponderance of the future burden of any past under collection to sectors where use per customer has dropped. Similarly, it would credit the preponderance of any over collection to sectors where use per customer has increased.

Q. Does this conclude your testimony, Mr. Hoff?

A. Yes, it does.