BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC SERVICE TO ELECTRIC CUSTOMERS IN THE STATE OF IDAHO.	)))))))	CASE NO. IPC-E-03-13

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MAGGIE BRILZ

Q. Please state your name, address, and present occupation.

Q. Please state you name and business address.

A. My name is Maggie Brilz. My business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company as Director of Pricing.

Q. Please describe your educational background.

A. In May of 1980 I received Bachelor of Arts Degrees in Economics and Psychology from Smith College in Northampton, Massachusetts. In 1998 I completed the University of Idaho's Public Utilities Executive Course in Moscow, Idaho. I have also attended numerous seminars and conferences on pricing issues related to the utility industry and have attended seminars and courses involving public utility regulation.

Q. Please describe your business experience with Idaho Power Company.

A. I started employment with Idaho Power Company in November of 1984 as a Financial Analyst in the Planning Department. In 1986 I was promoted to the position of Rate Analyst in the Rate Department. My duties as a Rate Analyst included the development of alternative pricing structures, the analysis of the impact on customers of rate design changes, the preparation of cost-of-service studies, and the administration of the Company's tariffs. In July of 1993 I was promoted to Rate Design Supervisor. In that capacity I also became responsible for the overall rate design activities of the Rate Department. In October of 1996 I was promoted to my current position of Director of Pricing in the Pricing and Regulatory Services Department.

Q. What is the scope of your testimony in this proceeding?

A. My testimony will address the Company's class cost-of-service study and the Company's rate design proposals for the tariff and special contract customers.

<u>Class Cost-of-Service Study</u>

Q. Please describe the methodology used to prepare the class cost-of-service study submitted in this proceeding.

A. The class cost-of-service study submitted in this proceeding uses the Weighted 12 Coincident Peaks allocation method. This study uses the same methodology as previously filed by the Company in Case No. U-1006-185, Case No. U-1006-265A, and Case No. IPC-E-94-5 and used by the Commission in the allocation of the revenue requirement among customer classes in those cases.

Q. What procedures were used in the preparation of the fully distributed or embedded class cost-of-service study?

A. There are two general steps used in preparing a fully distributed or embedded class cost-of-service study. The first step is to determine the total costs of providing electric service, adjusted for normal weather and water conditions. The next step is to establish a methodology for the separation of those costs among customer classes.

Q. What total costs of providing electric service have been allocated to the various customer classes in the class cost-of-service study?

A. The total costs of providing electric service to the Idaho jurisdiction included on Mr. Obenchain's Exhibit No. 30 have been allocated to the various classes.

Q. What methodology was used for the separation of costs among customer classes?

A. The methodology for separating costs among classes consists of a three-step process generally referred to as classification, functionalization, and allocation. In all three steps, recognition is given to the way in which the costs are incurred by relating these costs to the way in which the utility is operated to provide electrical service.

Q. Please explain the meaning of classification.

A. Classification refers to the identification of cost as being either customer-related, demand-related, or energy-related. These three cost components are used to reflect the fact that an electric utility is not simply in the business of selling electric energy, even though it may sometimes appear to the customer that only energy, as measured in kilowatt-hours, is purchased. In fact, the customer is also buying the ability to have service available at any point in time. Secondly, the customer is buying capacity or the ability to receive as much power as is required at a point in time. Most power supply facilities (generation and transmission) generally are considered to fall into this capacity category. And finally, the customer is buying energy or the ability to do useful work over an extended period of time. These three concepts of availability, capacity and energy are related to the three components of cost designated as customer, demand and energy components, respectively. In order to classify a particular cost by component, primary attention is given to whether the cost varies as a result of changes in the number of customers, changes in demand imposed by the customers, or changes in energy use.

Q. What are some examples of customer-, demand-, and energy-related costs?

A. Examples of customer-related costs are the investment in meters, a portion of the investment associated with distribution facilities, the costs associated with meter reading and billing, and the costs associated with maintaining the availability of service regardless of whether service is actually taken. Demand-related costs are investments in generation, transmission, and distribution plant and the associated operation and maintenance expenses necessary to accommodate the maximum demand imposed on the Company's system. Energy-related costs are generally the variable costs associated with the operation of the generating plants, such as fuel, although due to the hydro production capability of the Company, a portion of the hydro and thermal generating plant investment is usually classified as energy-related.

Q. Please discuss the approach used to classify customer-, demand-, and energy-related costs.

A. The Company has used the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners as its primary guide to the classification of customer-, demand-, and energy-related costs.

Q. Please explain the meaning of functionalization.

A. In addition to classification, costs must be functionalized; that is, identified with utility operating functions. Operating functions recognize the different roles played by the various facilities in the electric utility system. In the Company's accounts these various roles are already recognized to some degree, particularly in the recording of plant costs as production-, transmission-, or distribution-related. However, this functional breakdown is not in sufficient detail for cost-of-service purposes. Individual plant items are examined and, where possible, the associated investment costs are assigned to one or more operating functions so that the costs may be allocated among classes of customers.

Q. Please explain the process of allocation.

A. The process of allocation is merely one of apportioning the total jurisdictional cost among classes by introducing allocation factors into the process. An allocation factor is nothing more than an array of numbers which specifies the class value or share of a total jurisdictional quantity.

Once individual costs have been allocated to the various classes of service, it is possible to total these costs as allocated and thus arrive at a breakdown of utility rate base and income by class. The results are stated in a summary form to measure adequacy of revenues for each class. The measure of adequacy is typically the rate of return earned on rate base compared to the requested rate of return.

Q. Have you prepared or supervised the

preparation of the fully distributed or embedded class cost-of-service study submitted in this proceeding?

A. Yes. Using the cost information provided to me by Mr. Obenchain, I prepared the fully distributed or embedded class cost-of-service study. This study was prepared using the Weighted 12 Coincident Peaks allocation method. It is identified as follows:

<u>Exhibit</u>	<u>Description</u>
Exhibit No. 37	Functionalization and Classification of Costs
Exhibit No. 38	Summary of Functionalized Costs
Exhibit No. 39	Allocation to Classes
Exhibit No. 40	Development of Weighted Demand and Energy Allocators
Exhibit No. 41	Revenue Requirement Summary

Q. Please describe Exhibit No. 37.

A. Exhibit No. 37 contains 115 pages and consists of 10 Cost Functionalization and Classification Tables. The functionalization and classification of each component of rate base, operating revenue and expense is treated in detail in these tables. The tables are shown in the following sequence:

<u>Table No.</u>	<u>Description</u>
1	Electric Plant in Service
2	Accumulated Provision for Depreciation

3	Additions and Deletions to Rate Base
4	Operating Revenues
5	Operation and Maintenance Expenses
6	Depreciation and Amortization Expense
7	Taxes Other Than Income Taxes
8	Income Taxes
9	Development of Labor Related Allocator
10	Functionalization Allocators

Q. What is the significance of the column headed "Allocator"?

A. This column identifies, by symbol, the basis for each allocation. For example, for Accounts 310 through 316, Steam Production, shown at line 20 on page 1, the constant "PI-S" is used to allocate the total investment in steam production plant to the appropriate functions. The resultant functionalization of costs may itself serve as a basis for subsequent allocations. This use is illustrated at line 115 on page 16 where the accumulated depreciation for steam production plant is allocated by the functionalization of costs at line 20.

Q. Please describe the classification of plant utilized in the class cost-of-service study.

A. In the class cost-of-service study all steam and hydro production plant has been classified on a demand and energy basis using the methodology found preferable by this Commission in prior general rate proceedings. The energy portion of the steam and hydro production investment has been determined by use of the Idaho jurisdictional load factor of 55.26 percent. The computation of the Idaho jurisdictional load factor is included in my workpapers. By application of the load factor ratio to the steam and hydro production plant investment, the energy-related portion is easily determined. The balance of the steam and hydro production plant investment is then classified as demand-related. All other production plant and transmission plant has been classified as demand-related.

Q. Would you describe how distribution plant has been classified?

A. Distribution substation plant, Accounts 360, 361, and 362, has been classified as demand-related. Distribution plant Accounts 364, 365, 366, 367 and 368 were classified as either demand-related or customer-related using the ratio of the fixed and variable portions of the Company's system peak during the three-year period 2000 through 2003. The fixed portion of the Company's system peak was set equal to the near-minimum, or first percentile, hourly system load during this three-year period. The variable portion was set equal to the remaining share of the peak load.

Q. Would you please describe the

functionalization of general plant?

A. General plant was functionalized based on total production, transmission, and distribution plant. As a result, a portion of general plant was assigned to each production, transmission, and distribution function based on each function's proportion to the total.

Q. How was the accumulated provision for depreciation functionalized?

A. The accumulated provision for depreciation was functionalized using the resulting functionalization of costs for the appropriate plant item. For example, the accumulated depreciation for steam production plant shown at line 115 on page 16 is functionalized based on the functionalization of steam production plant in service at line 20.

Q. Please describe Table 3 of Exhibit No. 37.

A. Table 3 indicates the functionalization of all other additions to and deductions from rate base. Deductions from rate base include customer advances for construction and accumulated deferred income taxes. Customer advances have been functionalized based on the distribution plant investment against which the advances apply. Accumulated deferred taxes have been functionalized based on total plant investment. Additions to rate base consist of materials and supplies, which have been functionalized based on the appropriate plant function, fuel inventory, which has been functionalized based on energy production, and prepaid items, which have been functionalized based on labor expenses or the appropriate plant function depending on the type of prepayment. Deferred conservation expenses have been functionalized based on the Idaho jurisdictional load factor resulting in 55.26 percent of the deferred expenses being functionalized to energy production and the remainder being functionalized to demand production.

Q. Please describe the functionalization of other revenue shown on Table 4 of Exhibit No. 37.

A. Other revenue is functionalized based on either the functionalization of the related rate base item or, in the situation where a particular revenue item may be identified with a specific service, the functionalization of the specific service item.

Q. Briefly describe the method by which operation and maintenance expenses were functionalized.

A. The functionalization of operation and maintenance expenses is detailed on Table 5 of Exhibit No. 37. In general, the basis for the functionalization may be readily interpreted from the Exhibit, particularly since in most cases the functionalization is the same as that for the associated plant.

Q. How is supervision and engineering expense treated throughout the allocation of operation and maintenance expenses?

A. For each applicable expense account in each functional group, the labor component is separately functionalized in accordance with the detail provided on Table 9 of Exhibit No. 37. Referring to pages 91 through 105 of Table 9, it can be seen that the total of allocated labor in each functional group becomes the basis for the functionalization of supervision and engineering expense. For example, for Account 535 at line 678, the labor related supervision and engineering expense is functionalized based on lines 679-683 which represent the cumulative labor as functionalized for Accounts 536 through 540 shown on page 91 of Exhibit No. 37. In a similar fashion, the allocation of supervision and engineering associated with hydraulic maintenance expense, Account 541, is based on the composite labor expense for Accounts 542 through 545, as expressed by lines 686-689. Total functionalized labor expense serves the additional purpose of functionalizing employee pensions and other labor-related taxes and expenses. Table 9 details the development of all labor-related functionalization factors used in this study.

Q. Please describe the functionalization of depreciation expense, taxes other than income, and income taxes shown on Tables 6, 7, and 8, respectively.

A. Depreciation expense is functionalized based on the function of the associated plant. Taxes other than income are also functionalized based on the function of the source of the tax. Deferred income taxes are functionalized based on total plant investment. The functionalization of federal and state income taxes is based on the functionalization of total rate base and expenses and is discussed in more detail in my testimony regarding the allocation of costs to classes of customers.

Q. Please describe Exhibit No. 38.

A. Exhibit No. 38 summarizes in row format the functionalized costs for each component of rate base and expenses shown across the columns on Exhibit No. 37.

Q. Please describe Exhibit No. 39.

A. Exhibit No. 39 details the allocation of the summarized costs shown on Exhibit No. 38 to each class of customer including the special contract customers. The Exhibit also includes a summary of results showing the actual rate of return earned for each customer class and special contract customer. The Exhibit includes the following tables:

Table No.	Description
1	Plant in Service
2	Accumulated Reserve for Depreciation

3	Amortization Reserve
4	Customer Advances for Construction
5	Accumulated Deferred Income Taxes
6	Acquisition Adjustment
7	Working Capital
8	Deferred Programs
9	Subsidiary Rate Base
10	Substation CIAC
11	Other Revenue
12	Operation & Maintenance Expenses
13	Depreciation Expense
14	Amortization of Limited Term Plant
15	Taxes Other Than Income
16	Provision for Deferred Income Taxes
17	Investment Tax Credit Adjustment
18	State Income Tax
19	Federal Income Tax
20	Allocation Factor Summary

Q. Briefly describe the manner in which you allocated the summarized costs shown on Exhibit No. 38 to each class of service as shown on Tables 1 through 17 of Exhibit No. 39.

A. In an effort to weight the monthly contributions to the total system peak in a fashion which reflects the marginal costs of the Company's seasonal load requirements, I have allocated demand-related costs according to a Weighted 12 Coincident Peaks allocation method.

Q. Is the Weighted 12 Coincident Peaks methodology used in the current class cost-of-service study the same methodology used in previous studies filed with the Commission?

A. The philosophical approach is the same in that the methodology is intended to strike a balance between backward-looking costs already incurred and forward-looking costs to be incurred in the future. However, the nature of the Company's marginal costs has changed since the early 1990s. As a result, the methodology used to compute the weighted demand-related allocation factors has been revised slightly.

Q. How has the nature of the Company's marginal costs changed since the early 1990s?

A. According to the Company's 2002 Integrated Resource Plan (IRP), the Company has identified capacity deficits in the months of June, July, August, November, and December only. During all other months, no capacity deficits currently exist. The deficits in the five months cited above are driving the need for additional peaking resources. Consequently, the Company faces capacity, or generation related, marginal costs in only five months of the year. During the remaining seven months, the Company has no current need for additional resources. Hence there is no generation-related marginal cost for these seven months. In the early 1990s the Company's analysis showed a generation-related marginal cost for all months of the year except September and October.

Q. Does the Company's analysis for transmission-related marginal costs show the same result as for generation capacity?

A. No, it shows slightly different results. Again, according to the Company's 2002 IRP, the Company currently anticipates transmission deficits during only the months of June, July, and August. As a result, the Company faces transmission-related marginal costs during only these same three months.

Q. What are the weighted allocation factors used in the cost-of-service study?

A. The allocation factor D10 is used to allocate generation capacity-related costs. The allocation factor D13 is used to allocate transmission-related costs. The allocation factor E10 is used to allocate energy-related costs. The detail for the development of the weighted allocation factors can be found on Exhibit No. 40.

Q. How has the Company used the marginal costs to determine the Weighted 12 Coincident Peaks allocation factors?

A. First, the actual coincident peaks for each customer class were used to derive actual D10 and D13 ratios. Second, the actual coincident peaks weighted by the five monthly marginal costs for generation and the three monthly marginal costs for transmission were used to derive weighted D10 and D13 ratios. Finally, the average of the actual and weighted D10 and D13 ratios were computed for use in allocating costs among customer classes.

Q. Was the methodology used to compute the demand-related weighted allocation factors used to compute the weighted energy-related allocation factors?

A. No. Because the Company operates its system by continually balancing energy generation and purchases, it faces monthly marginal energy costs. Therefore the methodology used to determine the weighted energy allocation factors is the same as that used in the Company's previous filings. The monthly marginal energy costs were used to weight the normalized monthly energy usage for each customer class and special contract customer. I then totaled the results for each customer class and divided the customer class totals by the jurisdictional total weighted value to establish the E10 ratio for each class.

Q. Were any other changes incorporated into the derivation of the weighted demand and energy allocation factors?

A. Yes. In order to identify costs by summer and non-summer seasons to facilitate the Company's rate design proposals, I calculated weighted factors for both the summer season, defined as the months of June, July, and August, and the non-summer season, defined as all other months. Accordingly, the summer and non-summer weighted demand allocation factors used for the allocation of the demand-related portion of production plant and for the allocation of transmission plant are designated as D10S, D10NS, D13S, and D13NS, respectively. The summer and non-summer weighted energy allocation factors are designated as E10S and E10NS, respectively.

Q. Have the marginal costs been used to develop the Company's revenue requirement?

A. No. The marginal costs have been used solely for purposes of developing allocation factors and not for purposes of developing the Company's revenue requirements.

Q. What was the method by which you allocated costs associated with distribution plant?

A. The allocation of the capacity components of distribution plant, both primary and secondary, was by use of the coincident group peak demands for each customer class identified as demand allocation factors D20, D30, D50, and D60. The allocation of the customer components of distribution plant, both primary and secondary, was by use of the average number of customers identified as customer allocation factors C20, C30, C50 and C60.

Q. What was the method by which you allocated costs associated with customer accounting and customer assistance expenses?

A. The principal customer-related expenses which require allocation are meter reading expenses, customer records and collections, uncollectible accounts, and customer assistance expense. The meter reading and customer account expenses were allocated based upon a review of actual practices of Idaho Power Company in reading meters and preparing monthly bills. The allocation of uncollectible amounts again was based upon a review of actual Idaho Power Company data. Customer assistance expenses were allocated based on the average number of customers in each class.

Q. Does Exhibit No. 39 include a listing of the allocation factors used to allocate to classes the various costs shown on Tables 1 through 17?

A. Yes. Table 20 of Exhibit No. 39 includes a listing of each allocation factor.

Q. How did you allocate state and federal income tax to each customer class and special contract customer as shown on Tables 18 and 19?

A. The state and federal income taxes for the

Idaho jurisdiction provided to me by Mr. Obenchain were allocated to each customer class and special contract customer on the basis of income before income taxes. The worksheet showing this allocation is included in my workpapers. Tables 18 and 19 show the functionalization of these allocated taxes to each customer class.

Q. What method was used to functionalize the state and federal income taxes as shown on Table 18 and Table 19 of Exhibit No. 39?

A. State and federal income taxes were functionalized based on the functionalization of total rate base and expenses for each class. For example, the total summer power supply production rate base amount of $59,945,913 allocated to the residential class on Tables 1 through 10 of Exhibit No. 39 represents 9.33 percent of the total rate base amount of $642,356,205 allocated to the residential class. The state and federal income taxes allocated to the residential class ($783,038 and $6,799,290, respectively) are multiplied by this same percent to establish the summer power supply production components of $73,075 and $634,523 shown on Table 18 and Table 19. This same methodology is used for all functional components and customer classes shown on Tables 18 and 19.

Q. Please describe Exhibit No. 41.

A. Exhibit No. 41 is the revenue requirement summary based on the results of the class cost-of-service study. The section headed "Revenue Requirement for Rate Design" details the sales revenue required from each customer class and special contract customer. The sales revenue required includes return on rate base, total operating expenses, and incremental taxes computed using the net-to-gross multiplier of 1.642 provided to me by Mr. Obenchain. I have provided the results from this section to Mr. Gale. Mr. Gale's testimony addresses the allocation of revenue requirement among the customer classes.

Q. Were any adjustments made to the Company's data for any of the customer classes for purposes of the class cost-of-service study?

A. Yes. Currently, seven customers receive service under Schedule 19, Transmission Service level. After a review of these customers' facilities, it was determined that the facilities configuration for four of the seven customers is the same as the facilities configuration for customers taking service under Schedule 19, Primary Service level. However, these four customers, unlike Primary Service level customers, are currently paying a facilities charge for a portion of the investment in substation facilities required to provide service. In order to treat these customers consistently with other customers in the same situation, the Company intends to transfer these four customers to Primary Service level and discontinue the monthly facilities charge on the substation investment. An adjustment, as detailed by Mr. Obenchain in his testimony, has been made to the amount of annual facilities charge revenue to reflect this change.

Q. Does the Company's class cost-of-service study treat each service level on Schedule 9 and Schedule 19 as a separate customer class?

A. No, it does not. The three service levels, Secondary, Primary, and Transmission, available on both Schedule 9 and Schedule 19 are intended to provide flexibility in serving customers depending on the customer's facility requirements. For example, customers who own their own substations are served at Transmission Service level whereas customers who utilize non-dedicated Company-owned facilities are served at Secondary Service level. Customers who own their own secondary facilities, or who pay a facilities charge to the Company for use of the dedicated secondary facilities, are served at Primary Service level. After the adjustment I just described for the four Schedule 19 Transmission Service level customers, only three customers will be served at the Transmission Service level on Schedule 19. In addition, only one customer is served at Secondary Service level under Schedule 19. The remaining 100 customers are served at Primary Service level.

Therefore, for Schedule 19, the Transmission and Secondary customers are combined with the Primary Service level customers to form a single customer class for cost allocation purposes. For Schedule 9, the three Transmission Service level and the 112 Primary Service level customers are combined to form a single customer class for cost allocation purposes while the Secondary customers remain separate. This grouping of the various service levels prevents a very small group of customers from being treated as a single customer class.

Q. The Company's class cost-of-service study separately identifies contributions in aid of construction (CIAC) for distribution substations. Is this treatment of substation CIAC a departure from past practices?

A. Yes. In the past, the Company's class cost-of-service studies have included only the net amount of distribution substation investment. Consequently, no direct recognition of CIAC payments has historically been made on a customer class basis. As a result, all customer classes that were allocated a portion of distribution substation plant were provided a portion of the benefit associated with CIAC payments.

Q. What changes have been made to the current class cost-of-service study to address the CIAC issue?

A. First, rather than using net distribution substation investment (Accounts 360, 361, and 362) as the amount to be functionalized, classified, and allocated to classes, as has been the practice in previous studies, the current study uses the "net plus CIAC" distribution substation investment. Second, I directly assigned to each customer class the distribution substation CIAC amount specifically contributed by each class. Thus the class-specific CIAC contributions were used as direct offsets to the allocated distribution plant investment for each customer class in the derivation of net rate base. This methodology directly attributes the benefit associated with CIAC payments to the specific classes that made the contributions.

Q. Mr. Obenchain referred to an adjustment made to treat the monthly Operation & Maintenance (O&M) charges paid by Micron under its special contract as retail sales revenue. Would you please explain the rationale for this adjustment?

A. Micron currently pays a monthly O&M charge based on the total cost of the substation facilities required to deliver power and energy to its facility. The Company is proposing to eliminate the separate O&M charge and incorporate the costs associated with the substation facilities into Micron's standard charges. The adjustment to Micron's sales revenue was made in order to establish an appropriate base revenue amount.

Rate Design

Q. What are the objectives the Company is striving to achieve through its rate design proposals?

A. The Company is striving to achieve two main objectives. First, the Company is striving to establish prices which primarily reflect the costs of the services provided. Cost-based prices provide customers with clear signals about the costs of receiving service, reduce subsidies within customer classes, and result in a more equitable recovery of the costs of providing service. Second, the Company is striving to give customers price signals that reflect the variation in the costs of providing service during different times of the year and day. Mr. Gale addresses in his testimony the Company's policy regarding its pricing objectives.

Q. How does the Company propose to implement these objectives?

A. The Company proposes to implement these objectives by pricing the individual rate components closer to cost, by implementing seasonal pricing for Schedules 1, 7, 9 and 19, and by implementing time-of-use pricing for all customers taking service under Schedule 19.

Q. How does the Company plan to price the rate components closer to cost?

A. Historically, the energy charge on metered service schedules has been set at levels that recover not only the costs associated with providing energy but also a portion of the fixed costs associated with delivering energy and providing customer-related services. The Company plans to emphasize increases to both the demand and customer charges so that these components are more reflective of cost. This plan will result in less non-energy related costs being recovered through the energy charge.

Q. Why is the Company proposing seasonal rates for Schedules 1, 7, 9, and 19?

A. The Company faces its highest power supply costs during the months of June, July, and August. The Company also faces its highest peak usage during these same three months. In fact, it is the peak usage during these three months, along with the usually low hydro conditions during the months of November and December, which are driving the need for the Company to seek new peaking resources and to emphasize peak reduction in demand-side management programs utilizing the energy efficiency rider funds. Seasonal rates, which are higher in the months of June, July, and August than during the other nine remaining months, are intended to signal customers that consumption during the summer months is more costly. It is hoped that this signal will encourage reduced consumption during the peak months.

Q. Why is the Company not proposing seasonal rates for Schedule 24, irrigation service?

A. Irrigation service is by definition seasonal. The pricing structure for Schedule 24 already takes into account the seasonal nature of irrigation service.

Q. Why is the Company proposing time-of-use rates for Schedule 19 service?

A. Besides being more costly during the summer months, energy is more costly during certain hours of the day. The implementation of time-of-use rates for Schedule 19 customers, who currently have the metering in place to accommodate the hourly pricing, will provide the economic signal that energy is more costly during both the peak hours of the day and the peak months of the year. Again, like strictly seasonal rates, it is hoped that time-of-use rates will encourage reduced consumption both during the summer months as well as during the daily peak hours.

Q. What are the specific pricing objectives for the Company's various service schedules?

A. First, the Company plans to place more emphasis on the customer and demand components in its overall rate structure. Second, the Company plans to initiate seasonal energy pricing on all metered service schedules and both seasonal energy and seasonal demand pricing on all metered service schedules that are also demand metered. And finally, the Company plans to implement mandatory time-of-use pricing for all customers taking service under Schedule 19. The Company does not plan to change the current seasonal pricing structure for irrigation service, nor does it plan to implement seasonal pricing for unmetered schedules or for the special contract customers.

Q. How are the seasons defined for the Company's pricing proposals?

A. The summer season is defined as June 1 through August 31. The non-summer season is defined as September 1 through May 31.

Q. Are you proposing any changes to the criteria for determining service schedule eligibility?

A. I am not proposing any changes to the usage criteria for determining eligibility for service under Schedules 7, 9, and 19. However, I am proposing a change to the process used to review customers' eligibility.

Q. Would you please explain the change being proposed?

A. Yes. Currently, each customer taking service under Schedule 7, 9, or 19 is assigned an anniversary date that coincides with the date on which service under the schedule first began. Each year during the billing period in which the customer's anniversary date falls, the customer's usage during the past twelve months is reviewed to determine continued eligibility. Customers whose usage during the annual review period has changed such that they are no longer eligible for the existing schedule are moved to the appropriate schedule beginning with the next billing period. Although this process works well under most situations, there are cases in which there is a lag between changes in usage and the actual annual review. For example, under the current method where the annual review occurs on the customer's anniversary date, a customer taking service under Schedule 7 whose account is reviewed on July 1 may decide to install an additional piece of equipment that causes the monthly usage to increase over 3,000 kWh per month. This increase in usage would make the customer eligible for service under Schedule 9 after just three months. However, because the customer's account will not be reviewed again until the following July 1, the customer will continue receiving service under Schedule 7. In order to more closely match any change in usage with the most appropriate service schedule, I am proposing to eliminate the annual review on the customer's anniversary date. In its place, I propose to review each customer's account monthly. Based on this monthly review of the customer's most recent twelve months of usage, transfers to the appropriate service schedule will be timelier. The language on Schedules 7, 9, and 19 has been modified to reflect this change in process.

Q. Are you proposing any other changes that are common to several service schedules?

A. Yes. I am proposing that the Customer Charge included on Schedules 1, 7, 9, 19, 24, and 25 be renamed to Service Charge.

Q. Why is this change being proposed?

A. The current Customer Charge is intended to recover costs that do not vary with the amount of energy or capacity used. These costs include such items as a portion of the investment in distribution facilities, the investment in meters and service drops, meter reading, billing, and other customer service related expenses. The term Service Charge is more descriptive of these costs and, I believe, will be more easily explained to customers.

Q. What change is being proposed to the power factor requirement for Schedules 9, 19, and 24?

A. Currently, Schedules 9, 19, and 24 provide a means by which the measured kW may be adjusted if the customer's power factor is less than 85 percent. I am proposing this provision be revised to allow for the measured kW to be adjusted if the customer's power factor is less than 90 percent. This revision will more directly target cost recovery from those customers whose poor power factors result in the need for additional facilities investment by the Company. In order to provide ample time for customers to work with Company representatives to identify and implement solutions to improve power factor, I am proposing the 90 percent power factor requirement not become effective until November 1, 2004.

Q. Are you proposing any changes to the contracting provisions for large customers requiring 1,000 kilowatts (kW) or more of capacity?

A. Yes. I am proposing that any customer, except a customer receiving service under a special contract, who requires 1,000 kW or more of capacity at a single point of delivery enter into a service agreement with the Company specifying the amount of capacity required. By entering into an agreement, the customer will have certainty that facilities are in place to provide the agreed upon level of capacity and the Company will have information useful for its planning purposes. I have added a section to Rule C, Service Agreement, specifying this provision. I have also added a Uniform Service Agreement in tariff format to Rule C.

Q. Are you proposing any changes not directly related to the Company's rate design?

A. Yes. Based on previous Commission Orders, the unit avoided energy cost for cogeneration and small power production available under Schedule 89 is to be adjusted during the course of every Idaho Power general rate proceeding. Using the methodology previously ordered by the Commission, I have adjusted the unit avoided energy cost utilizing updated variable operation and maintenance costs and variable fuel costs for the Valmy plant.

Q. Have you prepared or supervised the preparation of certain exhibits relating to your rate design testimony?

A. Yes. I am sponsoring the following exhibits relating to rate design:

Exhibit	Description
Exhibit No. 42	Class Cost-of-Service Unit Costs
Exhibit No. 43	Summary of Revenue Impact and Calculation of Proposed Rates
Exhibit No. 44	Billing Comparisons and Rate Design Impacts of Proposed Rates
Exhibit No. 45	Derivation of Schedule 19 Charges
Exhibit No. 46	Derivation of Schedule 24 Charges
Exhibit No. 47	Derivation of Schedule 45 Standby Charges
Exhibit No. 48	Proposed Tariff in Legislative Format
Exhibit No. 49	IPUC No. 27, Tariff No. 101

Q. Please describe Exhibit No. 42.

A. Exhibit No. 42 shows the unit cost for each function for metered service schedules as determined through the fully distributed or embedded class cost-of-service study. The billing units shown in the column labeled (E) reflect the billing demands, normalized billing energy, basic load capacity, and number of billings. The unit costs shown on Exhibit No. 42 form the basis of the component charges for each service schedule.

Q. Please describe Exhibit No. 43.

A. Page 1 of Exhibit No. 43 is titled Summary of Revenue Impact. Each service schedule and special contract customer is listed with its number of customers, energy sales, and current revenue level. Column 5 shows the revenue adjustment to each customer class. Column 6 shows the revenue to be recovered by the rate design proposals based on the 2003 test year. Page 1 also lists the mills per kWh and percentage change in revenue for each customer class and special contract customer.

Pages 2 through 22 of Exhibit No. 43 indicate the rate calculations made, by billing component, for each service schedule and special contract customer.

Q. Please describe Exhibit No. 44.

A. Exhibit No. 44 shows the impact on customers' bills of the proposed rate designs for Schedules 1, 7, 9, 19, 24, and 25.

Q. Please describe Exhibit No. 45 and Exhibit No. 46.

A. Exhibit No. 45 details the derivation of the charges for Schedule 19. Exhibit No. 46 details the derivation of the charges for Schedule 24.

Q. Please describe Exhibit No. 47.

A. Exhibit No. 47 details the derivation of the updated charges for Standby Service under Schedule 45.

Q. Please describe Exhibit No. 48 and Exhibit No. 49.

A. Exhibit No. 48 includes the Company's rules, regulations, and service schedules indicating in legislative format the changes made to those rules, regulations, and schedules. Exhibit No. 49 is the proposed Idaho Public Utilities Commission No. 27, Tariff No. 101. This exhibit contains all the changes to the Tariff proposed by the Company in this proceeding.

Q. How have you organized your discussion of the Company's rate design proposals?

A. I have divided my discussion of the Company's proposed rate designs into six sections. The first section includes the discussion for the proposed rate structures for the Company's non-demand metered schedules. The second section addresses the Company's proposals for demand-metered schedules. The third section includes the discussion for the proposed rate structures for the Company's non-metered schedules. The fourth section addresses the Company's proposals for the special contract customers. The fifth section includes the rate design proposals for the Company's "rider" schedules for standby and alternate distribution service. The final section addresses the Company's proposals for its miscellaneous special contracts.

NON-DEMAND METERED SCHEDULES

Q. What are the Company's non-demand metered service schedules?

A. Residential Service and Small General Service, Schedules 1 and 7 respectively, are metered for kilowatt-hour (kWh) use only.

Q. What is the present rate structure for Residential Service under Schedule 1?

A. Presently, residential customers pay a Customer Charge of $2.51 and a base Energy Charge of 4.9303¢ per kWh.

Q. What is the revenue requirement to be recovered from Residential Service customers taking service under Schedule 1?

A. Based on Mr. Gale's Exhibit No. 61, the annual revenue to be recovered from Schedule 1 customers is $255,076,727.

Q. Please describe the rate design proposal for Schedule 1.

A. The rate design proposal for Schedule 1 is included on page 2 of Exhibit No. 43. The Service Charge is increased from $2.51 to $10.00 per month. The $10.00 Service Charge represents approximately 40 percent of the cost-of-service result of $24.61 shown at line 300 on page 1 of Exhibit No. 42. Both a summer and a non-summer Energy Charge are established with the summer charge 25 percent greater than the non-summer charge. The Energy Charge during the summer is 6.1375¢ per kWh. The Energy Charge during the non-summer is 4.9101¢ per kWh.

Q. What impact does this rate design have on Residential Service customers?

A. The typical monthly billing comparison for Residential Service customers appears on page 1 of Exhibit No. 44.

Q. Do you believe the increase in the Service Charge from $2.51 to $10.00 per month is detrimental to low income customers?

A. No, I do not.

Q. Are you proposing any other changes to Schedule 1?

A. Yes. I am making what I consider housekeeping changes to clarify that residential service is not applicable if service is utilized for a commercial purpose or if the customer's equipment does not conform to the Company's specifications for residential service.

Q. What is the present rate structure for Small General Service under Schedule 7?

A. Customers taking service under Schedule 7 pay a Customer Charge of $2.51 and a base Energy Charge of 5.9649¢ per kWh. Demand is not metered for Schedule 7 customers.

Q. What is the revenue requirement to be recovered from Small General Service customers taking service under Schedule 7?

A. Based on Mr. Gale's Exhibit No. 61, the total annual revenue to be collected from Schedule 7 customers is $20,328,148.

Q. Please describe the rate design proposal for Schedule 7.

A. The rate design proposal for Schedule 7 is included on page 3 of Exhibit No. 43. The Service Charge is increased from $2.51 to $10.00 per month. The $10.00 Service Charge represents approximately 40 percent of the cost-of-service result of $26.01 shown at line 360 on page 2 of Exhibit No. 42. Both a summer and a non-summer Energy Charge are established. The Energy Charge during the summer is 7.2868¢ per kWh. The Energy Charge during the non-summer is 5.8283¢ per kWh. As is the case for residential service, the Schedule 7 Energy Charge during the summer is 25 percent greater than the Energy Charge during the non-summer.

Q. What is the impact of this rate design on Small General Service customers?

A. Page 2 of Exhibit No. 44 shows the billing comparison between the existing rates and rate structure and the proposed rates and rate structure for typical billing levels.

Q. Are you proposing other changes to Schedule 7?

A. As I will explain in more detail as I describe the proposed changes to Schedule 24, Irrigation Service, I am proposing to add language to Schedule 7 that clarifies that it is not applicable to agricultural irrigation service after October 31, 2004.

<u>DEMAND-METERED SCHEDULES</u>

Q. What are the Company's demand-metered schedules?

A. The Company's demand-metered schedules are Large General Service, Large Power Service, and Irrigation Service, Schedules 9, 19, and 24, respectively. In addition, Schedule 25, Irrigation Service Time-of-Use Pilot Program, while not open to new participants, is still available to those who were taking service as of October 1, 2002.

Q. How are Schedule 9 and Schedule 19 interrelated?

A. Both Schedule 9 and Schedule 19 provide service at Secondary, Primary, and Transmission Service levels. As customers' loads change, they can transfer between Schedule 9 and Schedule 19 while continuing to take service at the same service level. Both Schedule 9 and Schedule 19 have a Demand Charge and a Basic Charge. The Demand Charge is assessed on peak demand each month while the Basic Charge is assessed on the average of the two highest peak demands for the current 12-month period.

Q. What is the current relationship between prices on Schedule 9 and Schedule 19?

A. Currently, the Basic Charge, the Demand Charge, and, with a slight deviation, the Customer Charge are the same within service level for both Schedule 9 and Schedule 19. For example, the Basic Charge for Primary Service level is $0.77 per kW per month for both Schedule 9 and Schedule 19; for Secondary Service level, the Basic Charge is $0.36 per kW per month for both Schedule 9 and Schedule 19. The Energy Charges for Primary and Transmission Service level for Schedule 9 are approximately 2.25 percent greater than the corresponding Energy Charges for the same service level for Schedule 19.

Q. Why has this relationship been established?

A. This relationship has been established to be reflective of cost and to facilitate customer transitions from Schedule 9 to Schedule 19 and vice versa.

Q. Does the Company's rate design proposal for Schedule 9 and Schedule 19 customers maintain this pricing relationship between schedules?

A. The rate design proposal for Schedule 9 and Schedule 19 maintains the relationship between the Basic Charge and the Demand Charge on each of the schedules. However, because time-of-use pricing is being proposed for Schedule 19 and not for Schedule 9, a direct relationship between the energy components is not maintained.

Q. What is the present rate structure for Schedule 9?

A. Service under Schedule 9 is taken at Secondary, Primary, or Transmission Service level. One hundred twelve customers take service at Primary Service, three customers take service at Transmission Service, and 16,919 customers take service at Secondary Service. All customers taking service under Schedule 9 pay an Energy Charge, a Demand Charge, a Basic Charge, and a Customer Charge. Customers taking Primary or Transmission service may also pay a Facilities Charge.

Q. Please describe the rate design proposal for Schedule 9.

A. The Company is proposing both seasonal Energy Charges and seasonal Demand Charges for Schedule 9. In addition, the Company is proposing increases to both the Service Charge and the Basic Charge.

Q. Does the rate design proposal have the same overall impact in terms of the percentage increase in revenue requirement for customers taking service under Secondary, Primary, and Transmission Service levels?

A. No. The results of the cost-of-service study indicated an overall increase in revenue of 8 percent for Secondary Service level customers and 24 percent for Primary and Transmission Service level customers (refer to line 233 on page 1 of Exhibit No. 41). In order to recognize this cost difference between service levels, the rate design proposal for Primary and Transmission Service level targets an average overall increase of 20 percent.

Q. What is the Service Charge for Schedule 9?

A. The Service Charge for Secondary Service under Schedule 9 is $21. This amount represents approximately 55 percent of the cost-of-service result of $37.74 shown at line 480 on page 3 of Exhibit No. 42. The Service Charge for Primary and Transmission Service is $500. This amount is the same charge established for Schedule 19 Primary Service and Schedule 19 Transmission Service and reflects the cost associated with the automated metering of customers at these voltage levels.

Q. What is the Basic Charge for Schedule 9?

A. The Basic Charge for Secondary Service is $.65 per kW of basic load capacity per month. The $.65 charge reflects approximately 50 percent of the cost of service for distribution facilities as shown at line 480 on page 3 of Exhibit No. 42. For Primary Service, the Basic Charge is $1.12 per kW of basic load capacity. The Basic Charge for Transmission Service is $.57. The Basic Charge for Primary Service and the Basic Charge for Transmission Service are the same as those for Schedule 19. The derivation of the $1.12 and $.57 charges is detailed later in my discussion of the Schedule 19 rate design.

Q. What is the Demand Charge for Schedule 9?

A. The Demand Charge for Secondary Service for the summer season is $4.00 per kW and for the non-summer season is $3.35 per kW per month. For Primary Service, the Demand Charge during the summer season is $3.94 per kW. During the non-summer season the Demand Charge for Primary Service is $3.25 per kW. The Demand Charge for Transmission Service is $3.80 per kW during the summer season and $3.15 per kW during the non-summer season. For the non-summer season, the Demand Charges for Secondary, Primary, and Transmission Service are the same as those for Schedule 19. The derivation of both the summer and non-summer Demand Charges is described in more detail in my discussion of the Schedule 19 pricing design.

Q. What is the Energy Charge for Schedule 9?

A. The Energy Charge for Secondary Service is 2.9442¢ per kWh during the summer and 2.5616¢ per kWh during the non-summer. For Primary Service, the Energy Charge is 2.5659¢ per kWh during the summer and 2.1823¢ during the non-summer. The Energy Charge for Transmission Service is 2.5087¢ per kWh during the summer and 2.1337¢ per kWh during the non-summer.

Q. How were the Energy Charges derived?

A. The differential between the summer and non-summer energy costs resulting from the class cost-of-service study for Schedule 9 is approximately 18 percent (refer to Exhibit No. 42, page 3, line 480). The Energy Charges for Primary Service were set to reflect this cost differential. The Energy Charges for Transmission Service were set to maintain the current relationship between the Energy Charges for Primary and Transmission Service. The Energy Charges for Secondary Service were set to recover the residual revenue requirement for the class while attempting to maintain a summer and non-summer differential close to 18 percent.

Q. Are you proposing any other changes to Schedule 9?

A. As I will explain in more detail as I describe the proposed changes to Schedule 24, Irrigation Service, I am proposing to add language to Schedule 9 that clarifies that it is not applicable to agricultural irrigation service after October 31, 2004.

Q. What is the revenue requirement to be recovered from Schedule 9?

A. Based on Mr. Gale's Exhibit No. 61, the total annual revenue to be collected from customers taking service under Schedule 9 is $123,864,097.

Q. What is the impact of this rate design on Large General Service customers?

A. As can be seen from page 3 of Exhibit No. 44, approximately 30 percent of the customers taking Schedule 9 Secondary Service receive an increase in their annual bills less than the 15 percent overall increase for the Secondary Service customers as a whole. Another 28 percent of the Secondary Service customers receive an increase of 15 percent to less than 20 percent. For Primary and Transmission Service level customers, approximately 43 percent of the customers receive an increase less than the 20 percent overall increase targeted for this group. Page 4 of Exhibit No. 44 shows the impact of the rate design proposal on customers taking service under Schedule 9 Primary or Transmission Service. For all service levels, customers with higher load factors receive less of an increase than customers with lower load factors.

Q. What is the present rate structure for

Schedule 19?

A. Service under Schedule 19, just like service under Schedule 9, is provided under Secondary, Primary, or Transmission Service levels. All customers taking service under Schedule 19 pay an Energy Charge, a Demand Charge, a Basic Charge, and a Customer Charge. Customers taking Primary or Transmission Service may also pay a Facilities Charge. In addition, Schedule 19 includes a 1,000 kW minimum billing demand and basic load capacity.

Q. What is the rate design proposal for Schedule 19?

A. The Company is proposing seasonal time-of-use rates be implemented on a mandatory basis for all customers taking service under Schedule 19. Under the Company's proposal, On-Peak, Mid-Peak, and Off-Peak energy prices would be in effect during the three summer months from June 1 through August 31. During all other months Mid-Peak and Off-Peak energy prices would be in effect. In addition to seasonal energy rates, the Company is also proposing summer and non-summer demand charges as well as an on-peak demand charge during the summer. Although the Company is proposing an increase to both the Service Charge and the Basic Charge, no seasonality is being proposed for these charges.

Q. What is the Service Charge for Schedule 19?

A. For all service levels, the Service Charge is

$500 per month. This amount represents approximately 70 percent of the cost-of-service result of $712.36 shown at line 720 on page 5 of Exhibit No. 42.

Q. What is the Basic Charge for Schedule 19?

A. The Basic Charge for Secondary Service is $.65 per kW per month, the same as that for Schedule 9 Secondary Service. For Primary Service, the Basic Charge is $1.12 per kW per month. This amount is approximately equal to the cost-of-service result of $1.11 shown on line 720 on page 5 of Exhibit No. 42. For Transmission Service the Basic Charge is set to $.57 per kW per month to maintain the existing relationship between the Primary and Transmission Service levels.

Q. Please describe the Company's proposal for time-of-use energy charges.

A. During the three summer months, the Company is proposing three time-of-use blocks. The On-Peak block is defined as 1 p.m. to 9 p.m. Monday through Friday. The Mid-Peak block is defined as 9 a.m. to 1 p.m. and 9 p.m. to 11 p.m. Monday through Friday and 7 a.m. to 11 p.m. Saturday, Sunday, and holidays. The Off-Peak block is defined as 11 p.m. to 7 a.m. every day. During the non-summer months, the Company is proposing just two time-of-use blocks. The Mid-Peak block during the non-summer is defined as 7 a.m. to 11 p.m. Monday through Saturday. The Off-Peak block is defined as 11 p.m. to 7 a.m. Monday through Saturday and all hours on Sunday and holidays. All times are in Mountain Time.

Q. What are the specific proposed energy prices?

A. The Energy Charges by service level and time period for each season are:

Time Period	Service Level Secondary	Service Level Primary	Service Level Transmission
Summer			
On-Peak	3.4354¢	2.7991¢	2.7368¢
Mid-Peak	3.0375¢	2.4749¢	2.4198¢
Off-Peak	2.7745¢	2.2606¢	2.2103¢
Non-Summer			
Mid-Peak	2.6661¢	2.1723¢	2.1239¢
Off-Peak	2.4928¢	2.0311¢	1.9859¢

Q. Please describe the Company's proposal for Demand Charges.

A. During the three summer months, the Company is proposing to implement a two-tiered Demand Charge for monthly peak demand. The Demand Charge for Billing Demand, which is the average kW supplied during the 15-minute period of maximum demand during the billing period, is $3.61 per kW for Secondary Service, $3.50 per kW for Primary Service, and $3.39 per kW for Transmission Service. For all service levels, an additional charge of $0.45 is assessed for each kW of On-Peak Billing Demand, which is the average kW supplied during the 15-minute period of maximum demand during the billing period for the on-peak hours. For customers whose peak demand during the billing period occurs during the on-peak period, the Billing Demand and the On-Peak Billing Demand will be the same. However, for customers whose peak demand occurs during the mid-peak or off-peak period, the Billing Demand will be greater than the On-Peak Billing Demand. During the non-summer months, only Billing Demand will apply. There is no On-Peak Billing Demand during the non-summer months. The Demand Charges for the non-summer months are $3.35 per kW for Secondary Service, $3.25 per kW for Primary Service, and $3.15 per kW for Transmission Service.

Q. Would you please provide an example of how the summer Billing Demand and On-Peak Billing Demand will affect customers?

A. Yes. Assume a Primary Service level customer has a peak demand for the billing period of 1,500 kW which occurs during the on-peak period. In this situation the Billing Demand and the On-Peak Billing Demand will equal 1,500 kW. This customer will pay a total of $3.95 for each kW of peak demand since the Billing Demand and On-Peak Billing Demand are the same ($3.50 per 1,500 kW of Billing Demand plus $.45 per 1,500 kW for On-Peak Billing Demand). However if this same customer has a peak demand for the billing period of 1,500 kW that occurs during the mid-peak or off-peak period with the highest peak demand during the on-peak period equal to 1,200 kW, the On-Peak Billing Demand will be less than the Billing Demand. In this situation, the customer will, on average, pay only $3.86 per kW of peak demand ($3.50 per 1,500 kW of Billing Demand plus $.45 per 1,200 kW of On-Peak Billing Demand).

Q. Are you aware of any utilities that charge for both peak demand during the month and on-peak demand during the month in a manner similar to the Billing Demand and On-Peak Billing Demand you are proposing for the summer season?

A. Yes. I am aware of at least three utilities that have similar pricing for demand: Southern California Edison charges for the monthly peak demand, the monthly on-peak demand, and the monthly mid-peak demand under its Schedule TOU-8; Pacific Gas and Electric charges for the monthly peak demand, the monthly peak-period demand, and the monthly partial-peak-period demand under its Schedule E-19; and Colorado Springs Utilities charges for both monthly on-peak and monthly off-peak demand under its Schedule E8T and E8S. Both Southern California Edison and Pacific Gas and Electric charge for on-peak demand during the summer season only.

Q. What approach was taken in determining the pricing proposal for Schedule 19?

A. A two-step approach was taken. First, seasonal charges that did not differentiate by time-of-use were developed. After the seasonal charges were developed, the next step was to create the time-of-use charges for the demand and energy components within each season. Exhibit No. 45 details the derivation of the seasonal, non time-of-use differentiated charges as well as the derivation of the seasonal, time-of-use charges.

Q. How were the seasonal charges developed?

A. The Energy Charges for each season were established to approximate the 17 percent cost differential between summer and non-summer energy costs resulting from the class cost-of-service study for Schedule 19 while at the same time maintaining the current relationship between the Energy Charges for each service level and recovering the residual revenue requirement given the proposed Service, Basic, and Demand Charges. The Demand Charge for Primary Service was developed by first establishing the non-summer Demand Charge at $3.25 per kW, which is approximately 10 percent greater than the Schedule 19 Primary Service cost-of-service result of $2.95 shown at line 720 on page 5 of Exhibit No. 42 and approximately equal to the Schedule 9 Primary Service cost-of-service result of $3.29 per kW shown at line 540 on page 4 of Exhibit No. 42. The summer Demand

Charge for Primary Service was then established at $3.94 per kW to reflect a 20 percent differential between the summer and non-summer Demand Charges. The Demand Charges for both non-summer and summer for Secondary and Transmission Service were then set to maintain the current relationship for these charges between the three service levels. The non-summer Demand Charge was set to $3.35 per kW for Secondary Service and to $3.15 per kW for Transmission Service. The summer Demand Charge was set to $4.00 per kW for Secondary Service and to $3.80 per kW for Transmission Service.

Q. Why was a 20 percent differential established between the summer and non-summer Demand Charges?

A. A 20 percent differential approximates the seasonal differential for energy-related costs and provides consistency with the differential between the summer and non-summer Energy Charges.

Q. What is the cost differential between summer and non-summer demand-related costs that is supported by the cost-of-service study?

A. The differential between the summer and non-summer demand-related costs supported by the cost-of-service study is approximately 80 percent (refer to line 720 on page 5 of Exhibit No. 42).

Q. How were the time-of-use Energy Charges developed?

A. The first step in developing the time-of-use Energy Charges was to determine the charge for the Mid-Peak time period for each season. As a starting point, the Mid-Peak charge was set equal to the seasonal Energy Charge established through the process I just described. For example, as a starting point, the summer Mid-Peak Energy Charge for Primary Service was set to 2.4686¢, the value of the seasonal, non time-of-use differentiated summer Energy Charge (refer to page 1 of Exhibit No. 45). For the summer charges, the second step involved determining the amount of increase or decrease from the Mid-Peak charge needed to establish the On-Peak and Off-Peak charges so that the target price differentials for the three time blocks were met. For the non-summer charges, the second step involved determining the amount of decrease from the Mid-Peak charge needed to establish the Off-Peak charge so that the target differential for the two time blocks was met. The final step involved minor adjustments to each charge to establish prices that recovered the revenue requirement amount.

Q. What were the target price differentials between the various time blocks that the Company was striving to achieve?

A. For the summer months, the target price differential between the on-peak and off-peak time periods is 25 percent. According to the Company's Power Supply

Planning Department, this differential represents the approximate difference in cost between an average market price for energy during the summer months of June, July, and August and a flat market price for the calendar year. The price differentials between the on-peak and mid-peak prices and the mid-peak and off-peak prices resulted from an iterative process in which the Company attempted to maintain the mid-peak price as close to the flat seasonal charge as possible, give a price signal to encourage shifting of load from the on-peak period to either the mid-peak or off-peak period, and recover the revenue requirement. For the non-summer months, the price differential between the mid-peak and off-peak prices resulted from an iterative process in which the Company attempted to maintain the same relationship as the summer mid-peak and off-peak prices while recovering the revenue requirement.

Q. How were the time-of-use Demand Charges developed?

A. The Demand Charges for the non-summer months for each service level were set equal to the seasonal, non time-of-use differentiated charges (refer to Exhibit No. 45 discussed earlier). The summer Demand Charge for Primary Service was derived by applying the same 13 percent differential as was established for the summer On-Peak and Mid-Peak Energy Charges to the summer non time-of-use differentiated Demand Charge of $3.94. The result of this calculation is $3.50. The summer Demand Charges for Secondary and Transmission Service were then set to maintain the current relationship between the service levels. The difference between $3.94 and $3.50, or $.45 (rounded), is the summer On-Peak Demand Charge. The On-Peak Demand Charge is set at $.45 for each service level in order to help make the adoption of this new charge simple for all customers.

Q. Does your rate design proposal include any revisions to the provision for a Facilities Charge under Schedule 19?

A. No. Customers taking Secondary Service will not be subject to a Facilities Charge. Customers taking Primary Service will continue to be required to either own all facilities, including transformers, beyond the point of delivery or pay the Company a monthly Facilities Charge of 1.7 percent times the Company's investment in those facilities. Customers taking Transmission Service will be required to own their own substations and all other facilities beyond the point of delivery. In some situations, customers taking Transmission Service may pay a monthly Facilities Charge of 1.7 percent times the Company's investment in certain facilities.

Q. What is the total annual revenue requirement to be collected from Large Power Service customers?

A. Based on Mr. Gale's Exhibit No. 61, the total annual revenue requirement to be collected from Schedule 19 is $ 62,703,671.

Q. What is the impact of the rate design on Large Power Service customers?

A. As can be seen from page 5 of Exhibit No. 44, approximately 25 percent of the customers taking service under Schedule 19 receive an increase in their annual bills less than the 14 percent overall increase for the Schedule 19 customers as a whole. Another 33 percent receive an increase of 14 percent to less than 16 percent. For the Schedule 19 customer group as a whole, customers with higher load factors receive less of an increase than customers with lower load factors.

Q. Are you proposing any other changes to Schedule 19?

A. Yes. Currently, customers are required to sign a Uniform Large Power Service Agreement with the Company in order to receive service under Schedule 19. If the customer refuses to sign the Agreement, service continues to be provided under Schedule 9, although technically, based on the eligibility criteria for Schedule 9, the customer is not eligible for service under Schedule 9. Over the past several years the Company has experienced an increase in the number of customers with loads greater than 1,000 kW who meet the criteria for service under Schedule 19 but who choose not to enter into an Agreement. The reasoning stated by some of the customers for not entering into an Agreement is the reluctance to make a 12-month commitment for service, particularly by some of the companies that operate nationally. In order to ensure that customers are placed on the appropriate service schedule based on their usage characteristics, I am proposing to eliminate the requirement that a Uniform Large Power Service Agreement be signed in order to receive service under Schedule 19. Without the requirement to enter into an Agreement, customers will be transferred onto and off of Schedule 19 automatically based on their usage. In addition, customers whose operations are going out of business will no longer be required to provide a twelve-month notice to the Company prior to having Schedule 19 service discontinued. Rather, as these customers' usage declines, they will be transferred to the appropriate general service schedule as indicated by the monthly review process. I have added language to Schedule 19 indicating that all Uniform Large Power Service Agreements will be cancelled effective June 1, 2004.

Q. What contracting requirements, if any, will customers taking service under Schedule 19 have?

A. Customers taking service under Schedule 19 will be required to enter into a Service Agreement with the Company specifying the level of capacity required to serve their facilities. I described this Service Agreement earlier in my testimony.

Q. Are you proposing any changes to the eligibility criteria for receiving service under Schedule 19?

A. No. Schedule 19 will remain available to customers who have three or more billing periods during a twelve-month period in which the metered demand equals or exceeds 1,000 kW. However, Customers whose loads are anticipated to immediately exceed 1,000 kW may request to take initial service under Schedule 19.

Q. What is the current rate structure for Schedule 24?

A. Service under Schedule 24 is classified as being either "in-season" or "out-of-season". The in-season for each customer begins with the customer's meter reading for the May billing period and ends with the customer's meter reading for the September billing period. The out-of-season encompasses all other billing periods.

Within the in-season, customers pay both an Energy Charge and a Demand Charge for the metered usage. During the out-of-season, customers pay an Energy Charge only. For the in-season, customers are subject to a $10.07

Customer Charge. The Customer Charge during the out-of-season is $2.50.

Both Secondary Service and Transmission Service levels are available under Schedule 24, although no customers are currently taking Transmission Service.

Q. Please describe the rate design proposal for Schedule 24.

A. I am proposing to keep the overall rate structure for the irrigation season as it is currently. Consistent with the Company's overall objectives, I propose to move the individual rate components closer to cost by emphasizing increases in the demand and customer components and the inclusion of less non-energy related costs in the energy charges.

Q. What approach did you take in determining the amount of increase for each rate component?

A. I first considered the percentage of overall revenue requirement identified by demand, energy, and customer component for irrigation service resulting from the cost-of-service study. These percentages established the target for each component and are shown in column 5 on Exhibit No. 46. Second, I determined the percentage of overall revenue by component currently provided by the existing base rates. These percentages are shown in column 4 on Exhibit No. 46. The difference, or gap, between the target and the actual percentage was then determined for each component. Customer, demand, and energy charges were then established at a level that adjusted revenue by 15 percent of the gap. Exhibit No. 46 illustrates the approach taken for each rate component.

Q. How were the rates for Transmission Service determined?

A. Once the component rates for Secondary Service were determined, the charges for Transmission Service were established to maintain the same relationship between service levels as currently exists.

Q. What is the Service Charge for Schedule 24?

A. The Service Charge for Secondary Service during the in-season is $25 per month. The Service Charge for Transmission Service during the in-season is $500 per month. This amount is the same charge established for Schedule 9 and Schedule 19 Transmission Service. For both Secondary and Transmission Service, the Service Charge during the out-of-season is $2.50 per month.

Q. What is the Demand Charge for Schedule 24?

A. The Demand Charge for Secondary Service is increased from $3.58 to $5.40 per kW per month. The Demand Charge for Transmission Service is increased from $3.37 to $5.08 per kW per month. The Demand Charge is billed to Schedule 24 customers during the in-season only.

Q. What is the Energy Charge for Schedule 24?

A. The Energy Charge for Secondary Service is increased from 2.8416¢ per kWh to 3.2634¢ per kWh during the in-season and from 3.6172¢ per kWh to 4.5731¢ per kWh during the out-of-season. The Energy Charge for Transmission Service is increased from 2.7021¢ per kWh to 3.1035¢ per kWh during the in-season and from 3.4396¢ per kWh to 4.3490¢ per kWh for the out-of-season.

Q. What is the impact of the rate design on Schedule 24 irrigation service customers?

A. Page 6 of Exhibit No. 44 shows the billing impact of the proposed rate design. As can be seen from page 6 of Exhibit No. 44, approximately 23 percent of the customers taking service under Schedule 24 receive an increase in their annual bills of less than 25 percent, the total overall percentage increase for the class as a whole. Another 31 percent of the customers receive an increase of just 3 percent or less above the overall class increase of 25 percent. The remaining customers receive an increase in their annual bills of 32 percent to greater than 50 percent.

Q. What are the usage characteristics of the Schedule 24 customers receiving increases less than and greater than 25 percent?

A. Because the rate design places an increased emphasis on capacity, the higher a customer's load factor, the more beneficial the rate structure tends to be in terms of the overall impact to the annual billing. As can be seen from page 6 of Exhibit No. 44, customers with the highest percentage increase in annual bills have the lowest load factors.

Q. What changes are being proposed for Schedule 25, Irrigation Service Time-of-Use Pilot Program?

A. Schedule 25 currently provides continued service until October 1, 2007 for those participants who were enrolled in the pilot program on October 1, 2002. The Company is not proposing any changes to this ongoing service availability at this time. However, the Company is proposing to revise the Schedule 25 Service and Demand Charges to be consistent with the charges for Schedule 24 and to increase the time-of-use rates to recover the revenue requirement.

Q. What are the rates being proposed for Schedule 25?

A. I am proposing that the in-season and out-of-season Service Charges, the Demand Charge, and the out-of-season Energy Charge proposed for Schedule 24 be implemented for Schedule 25. Under this proposal the in-season Service Charge is $25 per month, the out-of-season Service Charge is $2.50 per month, the Demand Charge is $5.40 per kW per month, and the out-of-season Energy Charge is 4.5731¢ per kWh. The $3.00 per month in-season Meter Charge remains the same. For the in-season, the On-Peak Energy Charge is 5.7110¢ per kWh, the Mid-Peak Energy Charge is 3.2634¢ per kWh, and the Off-Peak Energy Charge is 1.6317¢ per kWh.

Q. Would you please describe the methodology used to determine the in-season Energy Charges for Schedule 25?

A. As is currently the case, the Mid-Peak Energy Charge is set equal to the in-season Energy Charge under Schedule 24, or 3.2634¢ per kWh. The differential between the On-Peak Energy Charge and the Off-Peak Energy Charge is the same as that currently in place for Schedule 25. That is, the On-Peak Energy Charge is 75 percent greater than the Mid-Peak Energy Charge while the Off-Peak Energy Charge is 50 percent less than the Mid-Peak Energy Charge.

Q. What is the impact of these changes on the Time-of-Use Irrigation Service customers?

A. The overall increase for the customer group as a whole is 25 percent, the same percentage increase as for the irrigation customer class as a whole. As can be seen from page 7 of Exhibit No. 44, approximately 23 percent of the customers taking service under Schedule 25 receive an increase in their annual bills of less than 25 percent. Another 27 percent of the customers receive an increase of just 3 percent or less above the overall class increase of

25 percent.

Q. What are the usage characteristics of the Schedule 25 customers receiving increases less than and greater than 25 percent?

A. As is the case with Schedule 24, the rate design for Schedule 25 places an increased emphasis on capacity. As a result, the higher a customer's load factor, the lower the overall percentage increase. Conversely, the lower a customer's load factor, the higher the overall percentage increase.

Q. Are any other changes to Irrigation Service being proposed?

A. Yes. Currently, irrigation customers who request service be reconnected or transferred into their name are not charged an account processing charge or a reconnection charge if they provide ten working days advanced notice of the date reconnection or transfer of service is desired. This "waiver" of the account processing charge is unique for irrigation customers as all other customers receiving metered service are assessed an account processing charge or a reconnection charge when service is transferred or reconnected. I am proposing that irrigation customers be treated similarly to all other customers who request a service reconnection or transfer by assessing either a service reconnection charge or a service establishment charge in each situation where the service is performed.

Q. Will irrigation customers still be required to provide ten working days advance notice of the date they desire to have service reconnected or transferred?

A. No. The Company will process requests for service reconnections and transfers in the same manner as these requests are now processed for all other customers. In almost all situations, these requests will normally be processed within three working days.

Q. Why is the Company proposing to add these charges for irrigation service at this time?

A. Since the Company routinely began leaving irrigation service connected on a year-round basis in 1996, the number of customers requesting service disconnections has declined dramatically. Prior to 1996, irrigation service was disconnected for approximately 80 percent of the Company's irrigation customers at the end of the pumping season. Over the winter of 2002, irrigation service was disconnected for only about 20 percent of the Company's 15,280 irrigation customers. In 1996, the Company performed approximately 9,000 service reconnections for irrigation customers. In 2003, only 3,400 service reconnections for irrigation customers were performed. The Company believes it is equitable to have those customers who require the reconnection service pay for the service rather than having the costs shared by all customers. Requiring customers to pay a reconnection charge will eliminate a cross-subsidy between those irrigation customers who require service reconnections and those who do not. Similarly, charging the approximately 1,250 customers who annually require the Company to perform a special meter reading in order to transfer service into their names is more equitable and targets cost recovery from those customers who require the specific service.

Q. What are the reconnection charge and service establishment charge for irrigation customers being proposed by the Company?

A. Ms. Drake addresses the specific charges and their derivation in her testimony.

Q. What change is being proposed to the eligibility criteria for Schedule 24 and Schedule 25?

A. The current language under the Applicability section on both Schedule 24 and Schedule 25 states that service is "applicable to power and energy supplied to farm customers and organizations". Although the Company is confident that Schedule 24 and Schedule 25 are intended to be available to farm customers and farm organizations, the current wording has led to various interpretations. The Company intends to clarify the nature of service for which

Schedule 24 and Schedule 25 are applicable by replacing the existing language under the Applicability section with language that specifies that service is applicable to power and energy supplied to agricultural use customers operating water pumping or water delivery systems used to irrigate agricultural crops or pasturage and by changing the name of the schedule from simply Irrigation Service to Agricultural Irrigation Service.

Q. Are there any customers currently receiving service under Schedule 24 or Schedule 25 that would no longer be eligible for irrigation service with the adoption of the new applicability language?

A. Yes. There are approximately 768 customers currently receiving service under Schedule 24 and Schedule 25 that would no longer be eligible for continued irrigation service with the adoption of the new applicability language. The majority of these customers utilize service for the irrigation of golf courses, cemeteries, parks, school grounds, and common areas in subdivisions.

Q. What is the Company's plan for addressing this issue?

A. The Company plans to allow non-agricultural customers to continue receiving irrigation service under Schedule 24 or Schedule 25 through October 31, 2004. Effective November 1, 2004, any non-agricultural customers still receiving service under Schedule 24 or Schedule 25 would be transferred to the applicable general service schedule. In addition, on this date, any agricultural customer utilizing a water pumping or water delivery system and receiving service under either Schedule 7 or Schedule 9 would be transferred to Schedule 24.

Q. How many agricultural customers currently served under Schedule 7 or Schedule 9 would will be affected by this change?

A. Approximately 613 customers would be transferred from Schedule 7 or Schedule 9 to Schedule 24.

NON-METERED SCHEDULES

Q. What are the Company's non-metered service schedules?

A. The Company's non-metered schedules are Dusk to Dawn Customer Lighting, Unmetered General Service, Street Lighting Service, and Traffic Control Signal Lighting Service, Schedules 15, 40, 41, and 42, respectively.

Q. What is the present rate structure for Dusk to Dawn Customer Lighting on Schedule 15?

A. Customers taking service under Schedule 15 are charged on a per lamp basis. Lamps currently served under Schedule 15 include 100, 200, and 400 watt high pressure sodium vapor area lighting, 200 and 400 watt high pressure sodium vapor flood lighting, and 400 and 1,000 watt metal halide flood lighting. Under Schedule 15, customers pay a monthly Facilities Charge of 1.75 percent for all new facilities required for service.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 15?

A. Based on Mr. Gale's Exhibit No. 61, the annual revenue to be recovered from Schedule 15 customers is $1,458,416.

Q. The class cost-of-service study indicates that the rates for Schedule 15 service should be reduced by over 100 percent. Would you please explain this result?

A. Yes. Customers who require new facilities to be installed in order to receive service under Schedule 15 are charged a monthly facilities charge equal to 1.75 percent of the Company's investment in those new facilities. Prior to the implementation of the Company's current customer information system (CIS) in 2000, facilities charge revenue by customer class was not available. In addition, the way in which the Company tracks facilities for customers receiving non-metered service does not identify the total investment in new facilities installed to provide Dusk to Dawn Customer Lighting Service. In prior cost-of-service studies, the total facilities charge revenue collected from customers was allocated to customer classes based on the identified facilities investment for each class. This methodology resulted in no facilities charge revenue being directed to the Schedule 15 customer class. Rather, the facilities charge revenue that should have been directed to the Schedule 15 customer class was spread to other customer classes. Because the detailed information on facilities charge revenue is now available through the CIS, the current cost-of-service study directly assigns the appropriate amount of facilities charge revenue to each customer class, including the Schedule 15 class. However, the issue of tracking facilities so that new facilities installed to provide Dusk to Dawn Customer Lighting Service can be correctly identified has not been resolved. As a result, although the revenue is credited to the Schedule 15 customer class, the associated costs associated with the plant investment are not. Prior to filing its next general rate case, the Company will identify a methodology for correctly determining the new facilities associated with Dusk to Dawn Customer Lighting Service.

Q. Does this inconsistency in the model have negative implications for the other customer classes?

A. Although it would obviously be better to have the correct matching of the revenue and expenses, any impact to other classes is minimal. Based on the total amount of facilities revenue received from Schedule 15 customers, the maximum total original investment in new facilities should be approximately $6 million. The net amount of this investment included in rate base, after adjustments for depreciation, would be something less than $6 million. Compared to a total rate base amount for the Idaho Jurisdiction of $1.547 billion, the plant investment potentially attributable to the Schedule 15 customer class represents less than four tenths of one percent of total rate base.

Q. Please describe the rate design proposal for Schedule 15.

A. The rate design proposal for Schedule 15 is included on page 7 of Exhibit No. 43. The monthly charge for each lamp is simply increased on a uniform percent basis consistent with the overall 4.99 percent increase for the class as a whole.

Q. Is the Company proposing any other changes to Schedule 15?

A. Yes. The Company is proposing two changes related to the facilities required to provide Dusk to Dawn Customer Lighting. First, the Company is proposing to allow the lighting fixture to be installed on a customer-owned support acceptable to the Company rather than only on a Company-owned pole. Second, the Company is proposing that an up-front payment be made when new facilities are needed in order to provide the service rather than having the customer pay a monthly facilities charge on the new facilities.

Q. Why is the Company proposing to allow the fixture to be installed on a customer-owned support?

A. The Company is proposing to allow the fixture to be installed on a customer-owned support that is acceptable to the Company in order to allow more flexibility for customers. In several instances, a customer-owned pole or other structure could adequately provide the support needed to install a lighting fixture. Charging the customer an additional amount to install a new Company-owned pole when an exiting customer-owned structure exists is unnecessary. The Company would have the sole discretion to determine if a customer-owned support were acceptable. In addition, the Company would have the right to remove its lighting fixture from the customer-owned support if it were at any time determined by the Company that the support was unsafe or had the potential to cause damage to it or to other customers. Language has been added to Schedule 15 that specifies that by requesting the installation of a lighting fixture on a customer-owned support, the customer is indemnifying the Company from any liability associated with the installation of the lighting fixture on the customer's property and granting the Company permission to enter the customer's premises, including the customer-owned support, in order to maintain its lighting fixture.

Q. What changes are being proposed regarding the installation of new facilities to provide Dusk to Dawn Customer Lighting Service?

A. Customers who request Dusk to Dawn Lighting Service where Company facilities are not presently available are required to pay a monthly facilities charge of 1.75 percent for all new facilities installed to provide service. New facilities can include such items as poles, anchors, and conductors. If the facilities remain in service for their full useful lives, the Company is made whole on the transaction. However, if the customer requests the Company discontinue the lighting service and remove the facilities before the end of their useful lives, the Company is not made whole for the transaction. In order to avoid this situation, the Company is proposing that the customer pay the work order cost for the installation of new facilities at the time service is requested. No monthly facilities charge would then be required. If the customer requests the early removal of the lighting fixture and other facilities, the Company would still incur the labor costs associated with the removal. However, the Company would not be left with facilities for which it would not be able to recover its investment.

Q. What is the present rate structure for

Unmetered General Service under Schedule 40?

A. Customers taking service under Schedule 40 pay a flat Energy Charge based on estimated usage. Demand- and customer-related costs are recovered through the Energy Charge. The minimum bill for service under Schedule 40 is $1.50 per month.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 40?

A. Based on Mr. Gale's Exhibit No. 61, the annual revenue to be recovered from Schedule 40 customers is $952,976.

Q. Please describe the rate design proposal for Schedule 40.

A. The rate design proposal for Schedule 40 is included on page 14 of Exhibit No. 43. The Energy Charge remains flat and increases from 5.680¢ per kWh to 5.953¢ per kWh.

Q. Are any other changes being proposed to Schedule 40?

A. Yes. Schedule 40 is available to customers whose loads and hours of operation are fixed such that the monthly kWh consumption can be accurately determined. In order to ensure that Schedule 40 remains available only to loads that are fixed, I am proposing language that makes Schedule 40 unavailable for loads that have the potential to have variable usage. With this additional language, customers taking service under Schedule 40 who modify their existing equipment such that it has the potential for variation in usage or who install additional equipment that has the potential for variation in usage will no longer be allowed to take service under Schedule 40 and will be transferred to the appropriate metered service schedule.

Q. What is the present rate structure for Street Lighting Service, Schedule 41?

A. Charges for Street Lighting Service are based on a per lamp or per pole basis. Street Lighting is divided into two types: 1) Company-Owned, and 2) Customer-Owned. Schedule 41 does not allow new service for incandescent, mercury vapor, or fluorescent fixtures.

Q. Are you proposing any changes to the rate structure for Schedule 41?

A. Yes, I am. The current rate structure for Schedule 41 assumes energy is used only for the illumination of street lighting fixtures from dusk until dawn. However, because of the availability of wired outlets or energized plug-ins on the lighting standard, it is possible for customers to use energy for other purposes, such as illuminating holiday decorations. In order to accommodate customers who desire to use additional energy for non-street lighting purposes, the Company is proposing to add a metered service option under Schedule 41. Customers who utilize plug-ins on Company-owned facilities or who have wired outlets or plug-ins on customer-owned facilities will be required to have metered service.

Q. Is the Company changing its standard to the cut-off or shielded fixture?

A. Yes. The Company is changing its standard light luminaire from a drop-down lens fixture to a flat lens or cutoff fixture. The Company plans to use its existing inventory of drop-down lenses until it is exhausted or until March 1, whichever comes sooner. Beginning March 1, 2004, the cutoff fixture will be used exclusively. I have added language to Schedule 41 that addresses the accelerated replacement of drop-down lens fixtures with cutoff fixtures for those customers who are interested in converting to the cutoff fixture more rapidly than would normally occur through standard maintenance.

Q. Is the Company proposing changing the wattage of fixtures available under Schedule 41?

A. Yes. The Company is adding a 70-watt high pressure sodium vapor lamp. This size lamp has been the most requested lamp from customers who have enacted "Dark Sky" requirements. In order to minimize inventory and better meet customer requests, the Company is proposing no new service for the 200-watt high pressure sodium fixture and the addition of the 250-watt high pressure sodium fixture to the Company-owned options. These changes will result in the same wattage lamps being available for both Company-owned and customer-owned systems.

Q. Are you proposing any other changes to Schedule 41?

A. Yes. I am proposing what I consider to be two housekeeping changes. First, Schedule 41 currently has language specifying that underground circuits can be installed if the customer pays a monthly Facilities Charge of 1.75 percent times the cost difference between overhead and underground installation charges. This language is no longer applicable with the Company's current Rule H. Under the provisions of Rule H, customers are responsible for paying the total cost of any additional facilities required, either overhead or underground, to provide service. Therefore, I am proposing this language be deleted.

Q. Will this change eliminate the monthly facilities charge for customers who previously requested underground circuits?

A. No. Customers who previously agreed to pay a monthly facilities charge for the installation of underground facilities will continue to pay the charge.

Q. What is the second housekeeping change being proposed?

A. Schedule 41 currently has language stating that the services provided by the Company for customer-owned systems include the replacement of defective ballasts. With the current design of lighting fixtures, the ballasts are no longer separately replaced. Rather, the entire fixture is replaced. Therefore, I have removed the reference to the replacement of defective ballasts from the section describing the services performed by the Company for customer-owned systems.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 41?

A. Based on Mr. Gale's Exhibit No. 61, the annual revenue requirement for Schedule 41 is $1,899,531.

Q. Please describe the rate design proposal for Schedule 41.

A. Rates are designed for both non-metered and metered service. Customers who take non-metered service will continue to pay a monthly per-lamp charge depending on the wattage of the fixture installed. Customers who take metered service will pay a monthly per-lamp charge depending on the wattage of the fixture installed, a per kWh charge for each kWh of metered usage, and a monthly meter charge.

Q. How were the per-lamp charges determined?

A. As a starting point, the average unit cost for the fixture, bulb, and photocell was determined for each lamp type and wattage using the information available in the Company's property records. Sales tax, Company overheads, and labor expense were then added to the average unit cost to derive a loaded facilities-related cost. The monthly per-lamp facilities-related charge was derived by multiplying the loaded fixture cost by 1.75 percent (the monthly facilities charge rate). For non-metered service, the total monthly charge per lamp equals the monthly per-lamp facilities-related charge plus the applicable amount for the per-lamp energy consumption. For metered service, the monthly charge per lamp equals the sum of the monthly per-lamp facilities-related charge plus the metered kWh times 4.661¢ per kWh plus the $8.00 per month meter charge. The specific rate design proposal for Schedule 41 is included on pages 15 through 18 of Exhibit No. 43. I have included in my workpapers details on the average unit cost for each fixture, bulb, and photocell and the derivation of the loaded facilities-related cost.

Q. What is the present rate structure for Traffic Control Signal Lighting Service, Schedule 42?

A. Customers taking service under Schedule 42 pay a flat Energy Charge for each kWh of estimated energy use. Usage is estimated based on the number and size of lamps burning simultaneously in each signal and the average number of hours per day the signal is operated. There is no minimum charge under Schedule 42.

Q. What is the revenue requirement to be recovered from customers taking service under Schedule 42?

A. Based on Mr. Gale's Exhibit No. 61, the annual revenue requirement for Schedule 42 is $320,719.

Q. Please describe the rate design proposal for Schedule 42.

A. The rate design proposal for Schedule 42 is included on page 19 of Exhibit No. 43. The Energy Charge is increased from 3.105¢ per kWh to 3.495¢ per kWh.

Q. Is the Company proposing any other changes to Schedule 42?

A. Yes. Over the past several years the Company has experienced an increase in the number of traffic lighting systems that utilize LED bulbs, traffic sensors, and camera monitoring. The wide variety of wattages available in the LED bulbs as well as the variability in operating hours for the red, green, and amber bulbs facilitated by the presence of traffic sensors and cameras makes it difficult to accurately estimate the kWh consumption at each intersection. In order to eliminate this "guesswork", the Company is proposing that all new traffic control signal lighting systems installed on or after June 1, 2004 be metered to record actual energy consumption.

Q. Will traffic control signal lighting systems installed prior to June 1, 2004 be required to be retrofitted to allow metered service?

A. No. Systems installed prior to June 1, 2004 may be retrofitted with meters upon the mutual consent of the Company and the customer. However, the Company is not proposing at this time that existing systems be required to convert to metered service.

SPECIAL CONTRACT CUSTOMERS

Q. What are the Company's rate design proposals for its special contract customers?

A. Other than the proposal which I described earlier to eliminate the monthly O&M charge paid by Micron and incorporate the costs associated with the substation facilities into Micron's standard charges, the Company is not proposing any changes to the rate structures for Micron, J. R. Simplot Company, and DOE/INEEL. Accordingly, the existing rates for the special contract customers are simply increased uniformly to recover the revenue requirement as shown on Mr. Gale's Exhibit No. 61. The rates for Micron, J. R. Simplot Company, and DOE/INEEL are shown on pages 20, 21, and 22 of Exhibit No. 43, respectively.

STANDBY AND ALTERNATE DISTRIBUTION SERVICE

Q. Are any customers currently taking service under Schedule 45, Standby Service?

A. No, there are no customers taking Schedule 45 service.

Q. Are any revisions to Schedule 45 being proposed?

A. The Schedule 45 charges are being revised to reflect the updated cost information resulting from the cost-of-service study. However, no other changes are being made to Schedule 45.

Q. Have you prepared an exhibit showing the derivation of the updated charges for Standby Service?

A. Yes. Exhibit No. 47 details the derivation of the updated charges. The updated charges have been derived using the same methodology approved by the Commission in the Company's last general rate case, Case No. IPC-E-94-5.

Q. Are any customers currently taking service under Schedule 46, Alternate Distribution Service?

A. No.

Q. What changes are being made to Schedule 46, Alternate Distribution Service?

A. The Schedule 46 Capacity Charge is being updated from $1.26 per kW to $1.30 per kW to reflect the current cost of providing Alternate Distribution Service. The $1.30 amount is derived by summing the Distribution demand revenue requirement for Substations, Primary Lines, and Primary Transformers for Schedule 19 shown on page 5 of Exhibit No. 42 ($1,577,379; $3,205,775; and $274,457, respectively) and dividing this sum by the total billed kW of 3,903,470. This methodology is the same as that approved by the Commission in the Company's last general rate case, Case No. IPC-E-94-5.

MISCELLANEOUS CONTRACTS

Q. What are the miscellaneous contracts under which the Company is providing service?

A. The Company has entered into contracts with two customers to provide customized service otherwise provided under standard service schedules. First, the Company is providing standby service to the Amalgamated Sugar Company under the provisions of a Standby Electric Service Agreement dated April 6, 1998. Second, the Company is providing street lighting service utilizing cut-off lighting fixtures to the City of Ketchum under the provisions of an Electric Service Agreement dated June 12, 2001. Both of these agreements have been approved by the Commission.

Q. Are you proposing any changes to the standby charges under the Standby Electric Service Agreement with the Amalgamated Sugar Company?

A. Yes. I am revising the charges to reflect the updated cost information resulting from the cost-of-service study. The methodology used to update the charges is the same methodology used to establish the currently approved charges. Page 190 of Exhibit No. 48 shows the revisions to Schedule 31 to reflect these updated charges. I have included details on the derivation of the updated charges in my workpapers.

Q. Are you proposing any changes to the Electric Service Agreement with the City of Ketchum?

A. No. The Agreement with the City of Ketchum includes a provision specifying that if any shielded fixture provided under the agreement becomes available through a standard tariff offering, either party may give notice that they desire that shielded street lighting service be continued under the standard tariff offering and the Agreement will be terminated. Should the Commission approve the Company's revised Schedule 41, the Company intends to provide notice to the City of Ketchum, terminate the Electric Service Agreement, and provide shielded service to the City of Ketchum under Schedule 41.

Q. Does this conclude your testimony?

A. Yes, it does.