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IDAHO PUBLIC
UTILITIES COMMISSION

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.	)	CASE NO. IPC-E-08-10

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

TIMOTHY TATUM

1 Q. Please state your name and business address.

2 A. My name is Timothy E. Tatum and my business

3 address is 1221 West Idaho Street, Boise, Idaho.

4 Q. By whom are you employed and in what

5 capacity?

6 A. I am employed by Idaho Power Company

7 ("Company") as a Senior Pricing Analyst in the Pricing and

8 Regulatory Services Department.

9 Q. Please describe your educational background.

10 A. I received a Bachelor of Business

11 Administration degree in Economics from Boise State

12 University in 2001. In 2005, I earned a Master of Business

13 Administration degree from Boise State University. I have

14 also attended electric utility ratemaking courses including

15 "Practical Skills for the Changing Electrical Industry," a

16 course offered through New Mexico State University's Center

17 for Public Utilities, "Introduction to Rate Design and Cost

18 of Service Concepts and Techniques" presented by Electric

19 Utilities Consultants, Inc., and Edison Electric

20 Institute's "Electric Rates Advanced Course."

21 Q. Please describe your work experience with

22 Idaho Power Company.

23 A. I became employed by Idaho Power Company in

24 1996 as a Customer Service Representative in the Company's

1 Customer Service Center. In June of 2003, after seven
2 years in customer service, I began working as an Economic
3 Analyst on the Energy Efficiency Team. As an Economic
4 Analyst, I maintained proper accounting for Demand-Side
5 Management ("DSM") expenditures, prepared and reported DSM
6 program accounting and activity to management and various
7 external stakeholders, conducted cost-benefit analyses of
8 DSM programs, and provided DSM analysis support for the
9 Company's 2004 Integrated Resource Plan ("IRP").
10 In August of 2004, I accepted a position as a
11 Pricing Analyst in Pricing and Regulatory Services. As a
12 Pricing Analyst, I provided support for the Company's
13 various regulatory activities including tariff
14 administration, regulatory ratemaking and compliance
15 filings, and the development of various pricing strategies
16 and policies.
17 In August of 2006, I was promoted to Senior Pricing
18 Analyst. As a Senior Pricing Analyst, my responsibilities
19 have expanded to include the development of complex
20 financial studies to determine revenue recovery and pricing
21 strategies. In 2007, I prepared the Company's cost-of-
22 service study submitted as part of Case No. IPC-E-07-08 and
23 served as the Company's cost-of-service witness in that
24 case.

1 Q. What is the scope of your testimony in this
2 proceeding?
3 A. My testimony will address the Company's
4 class cost-of-service studies and the allocation of revenue
5 requirement. My testimony will also address the derivation
6 of the Fixed Cost per Customer ("FCC") and Fixed Cost per
7 Energy ("FCE") rates to be used in determining the annual
8 Fixed Cost Adjustment ("FCA") under Schedule 54, Fixed Cost
9 Adjustment.

10 **CLASS COST-OF-SERVICE STUDY OVERVIEW**

11 Q. How many cost-of-service studies have you
12 prepared as part of this general rate case proceeding?
13 A. I have prepared three cost-of-service
14 studies as part of this general rate case proceeding.
15 Q. Please describe in general terms the process
16 used to prepare the three class cost-of-service studies.
17 A. There are two general steps used in
18 preparing a class cost-of-service study. The first step is
19 to determine the total costs of providing electric service,
20 adjusted for normal weather and water conditions. These
21 costs have been provided to me by Ms. Schwendiman on
22 Exhibit No. 46. The next step is to establish a
23 methodology for the separation of those costs among
24 customer classes.

1 Q. What methodology is used to separate costs
2 among customer classes?
3 A. The methodology for separating costs among
4 classes consists of a three-step process generally referred
5 to as classification, functionalization, and allocation.
6 In all three steps, recognition is given to the way in
7 which the costs are incurred by relating these costs to the
8 way in which the utility is operated to provide electrical
9 service.
10 Q. Please explain the meaning of
11 classification.
12 A. Classification refers to the identification
13 of a cost as being either customer-related, demand-related,
14 or energy-related. These three cost components are used to
15 reflect the fact that an electric utility makes service
16 available to customers on a continuous basis, provides as
17 much service, or capacity, as the customer desires at any
18 point in time, and supplies energy, which provides the
19 customer the ability to do useful work over an extended
20 period of time. These three concepts of availability,
21 capacity, and energy are related to the three components of
22 cost designated as customer, demand, and energy components,
23 respectively. In order to classify a particular cost by
24 component, primary attention is given to whether the cost

1 varies as a result of changes in the number of customers,
2 changes in demand imposed by the customers, or changes in
3 energy used by the customers.
4 Q. What are some examples of customer-, demand-
5 and energy-related costs?
6 A. Examples of customer-related costs are the
7 plant investments and expenses that are associated with
8 meters and service drops, meter reading, billing and
9 collection, and customer information and services as well
10 as a portion of the investment in the distribution system.
11 These investments and expenses are made and incurred based
12 on the number of customers, regardless of the amount of
13 energy used, and are therefore generally considered to be
14 fixed costs. Demand-related costs are investments in
15 generation, transmission, and a portion of the distribution
16 plant and the associated operation and maintenance expenses
17 necessary to accommodate the maximum demand imposed on the
18 Company's system. Energy-related costs are generally the
19 variable costs associated with the operation of the
20 generating plants, such as fuel. However, due to the hydro
21 production capability of the Company, a portion of the
22 hydro and thermal generating plant investment has
23 historically been classified as energy-related.

1 Q. What did you use as your primary guide in
2 classifying costs as either customer-, demand-, or energy-
3 related?
4 A. I used the Electric Utility Cost Allocation
5 Manual published, January 1992, by the National Association
6 of Regulatory Utility Commissioners as my primary guide to
7 the classification of customer-, demand-, and energy-
8 related costs.
9 Q. Please explain the meaning of
10 functionalization.
11 A. In addition to classification, costs must be
12 functionalized; that is, identified with utility operating
13 functions. Operating functions recognize the different
14 roles played by the various facilities in the electric
15 utility system. In the Company's accounts, these various
16 roles are already recognized to some degree, particularly
17 in the recording of plant costs as production-,
18 transmission-, or distribution-related. However, this
19 functional breakdown is not in sufficient detail for cost-
20 of-service purposes. Individual plant items are examined
21 and, where possible, the associated investment costs are
22 assigned to one or more operating functions, such as
23 substations, primary lines, secondary lines and meters.
24 This level of functionalization allows costs to be more

1 equitably allocated among classes of customers.

2 Q. Please explain the process of allocation.

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

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

17 Q. Please provide a general overview of the
18 class cost-of-service model.

19 A. The class cost-of-service model is comprised
20 of two separate Microsoft Excel workbooks. The first
21 workbook, called the Assign Module, performs the
22 classification and functionalization processes I described
23 earlier. This workbook categorizes the Idaho
24 jurisdictional costs identified by FERC account into

1 operating functions, such as production, transmission,
2 distribution, metering, customer service, etc. It also
3 categorizes the functional costs into demand-, energy-, and
4 customer-related classifications. For example, the Assign
5 Module categorizes the Company's investment in steam plant
6 into the production function and the demand- and energy-
7 related classifications.
8 The second workbook, called the Functionalized Cost
9 Module, or "FC Module" for short, performs the class
10 allocation process. This module allocates the classified
11 and functionalized costs developed in the Assign Module to
12 the various customer classes. For example, the FC Module
13 allocates the demand- and energy-related production costs
14 identified in the Assign Module to each of the Company's
15 customer classes and special contract customers. Each of
16 the major operations performed by this module is shown as a
17 separate worksheet to make the allocation process
18 transparent and easy to understand.
19 Q. Has the overall design of the class cost-of-
20 service model remained unchanged since the Company's last
21 general rate proceeding?
22 A. Yes. The overall design and functionality
23 of the model remains unchanged since the last general rate
24 case proceeding. However, some minor modifications have

been made to the logic and the placement of worksheets within the Assign Module in an effort to enhance the transparency of the process.

PREVIOUS MODIFICATIONS TO THE SYSTEM COINCIDENT DEMAND METHODOLOGY

Q. In the Company's 2005 general rate case proceeding, Case No. IPC-E-05-28, two changes were made to the methodology used to prepare the system coincident demands used in the allocation of fixed generation and transmission costs. Will you please review the nature of those changes?

A. Yes. In Order No. 29505 issued in the Company's 2003 general rate proceeding, Case No. IPC-E-03-13 ("03-13 Case"), the Commission opened Case No. IPC-E-04-23 for the purpose of evaluating cost-of-service issues raised during that general rate proceeding. Three "cost-of-service" workshops were held with interested parties between November 2004 and February 2005. During the workshop discussions, Idaho Power committed to revise the methodology used to convert billing period data to calendar month data and to prepare two cost-of-service studies as part of its next general rate case filing, one using a surrogate for a demand normalization methodology and one using the traditional methodology. Idaho Power fulfilled

1 that commitment in Case No. IPC-E-05-28 ("05-28 Case").

2 Q. Was the "workshop methodology" for

3 converting billing period data to calendar month data also

4 used in the current rate case proceeding?

5 A. Yes. Customers are billed throughout each

6 month and billing periods, or cycles, typically include

7 portions of more than one calendar month. Prior to the 05-

8 28 Case, billing period data was converted into calendar

9 month data using a simple linear interpolation. Daily

10 consumption during the billing period was assumed to be

11 flat, and weather effects were ignored. The aggregate

12 calendar month data was then used in the determination of

13 the coincident peak demands for each customer class.

14 Under the new "workshop methodology," billing period

15 data is now converted into calendar month data using a

16 nonlinear method based on load research data that utilizes

17 actual daily usage patterns. Total daily consumption is

18 assumed to fluctuate in proportion to the fluctuations in

19 the daily consumption of the load research sample

20 customers. This methodology captures the effects of

21 weather on energy consumption and improves the process of

22 determining coincident peak demand responsibility.

23 Q. In the Company's 05-28 Case, two cost-of-

24 service studies were prepared, one using a surrogate demand

1 normalization methodology and one using the traditional
2 methodology. Has the Company selected a preferred method
3 for determining the class coincident peak demands for use
4 in this case?
5 A. Yes. After evaluating the two approaches
6 for determining the class coincident peak demands, Idaho
7 Power's Load Research Department has recommended the
8 surrogate demand normalization methodology as the preferred
9 approach. This "normalized" approach serves to mitigate
10 the impact of unusual weather conditions that may exist in
11 a test year.
12 The surrogate demand normalization methodology uses
13 the five-year median demand ratios from the load research
14 sample applied to the normalized monthly energy values for
15 each customer class to determine the coincident peak
16 demands by class. This methodology reduces the effect of
17 any atypical demand ratios that might exist in a given test
18 year due to unusual weather conditions.
19 **PROPOSED MODIFICATIONS TO**
20 **THE SYSTEM COINCIDENT DEMAND METHODOLOGY**
21 Q. Are you proposing any other changes to the
22 manner in which the coincident peak demands are determined?
23 A. Yes. As part of this general rate case
24 proceeding, I am proposing an additional modification to

1 the method used to derive the coincident peak demand values
2 in an attempt to better reflect the impact that the
3 Irrigation Peak Rewards program has on the Company's peak
4 demands.
5 Q. Please provide an overview of the structure
6 and purpose of the Irrigation Peak Rewards program.
7 A. The Irrigation Peak Rewards program is a
8 demand response program available to agricultural
9 irrigation customers with pumps of 75 horsepower and
10 greater. The program is designed to reduce peak demand by
11 turning off participating irrigation pumps during peak
12 demand hours during the irrigation season in exchange for a
13 financial incentive. Through this program, the Company has
14 been successful in reducing load during the summer
15 afternoon hours when costs to provide energy are typically
16 higher.
17 Q. Please describe how the process used to
18 derive the class coincident peak demands has been modified
19 to better reflect the impact that the Irrigation Peak
20 Rewards program has on the Company's peak demands.
21 A. As described earlier in my testimony, the
22 Company's surrogate demand normalization methodology for
23 estimating system coincident demands utilizes five years of
24 load research sample data to derive monthly five-year

1 median system coincident demand factors for each customer
2 class. A system coincident demand factor is the ratio of
3 the system coincident demand to the average demand. To
4 derive the monthly system coincident demands, the monthly
5 five-year median factors from each sample are applied to
6 the associated population's monthly average demands for the
7 test year.
8 This year, a modified procedure was developed to
9 incorporate the system coincident demand reductions from
10 the Irrigation Peak Rewards program into the system
11 coincident demands for the Irrigation class. To accomplish
12 this objective, the Irrigation class's system coincident
13 demand factors for 2004-2007 were first revised to reflect
14 what the system coincident demands would have been absent
15 the Irrigation Peak Rewards program by removing all of the
16 program participants from the irrigation load research
17 sample. The remaining nonparticipants in the sample were
18 used to determine the revised system coincident demand
19 factors with no demand reduction from the program. Since
20 the program began in 2004, the system coincident demand
21 factors for 2003 did not need revision.
22 Next, the resulting "non-participant" system
23 coincident demand factors were adjusted to reflect the full
24 impact of the coincident demand reductions of the

1 Irrigation Peak Rewards program. If the time of the
2 historical system peak was outside of the Peak Rewards
3 window of operation from 4 p.m. to 8 p.m., there was no
4 adjustment to the system coincident demand factor. This
5 method is described in greater detail in my workpapers.

6 **PROPOSED MODIFICATIONS TO**
7 **THE COMPANY'S COST-OF-SERVICE METHODOLOGY**

8 Q. Please briefly describe each of the three
9 cost-of-service studies prepared as part of this general
10 rate case proceeding.

11 A. The three studies prepared as part of this
12 general rate case proceeding include a base case study
13 ("Base Case"), a modified base case study ("Modified Base
14 Case"), and a study identified as the "3CP/12CP" study.
15 The Base Case study applies a methodology similar to that
16 used in the preparation of the cost-of-service study in the
17 03-13 Case, the last case in which the Commission approved
18 a study. The Modified Base Case study deviates from the
19 Base Case method in two ways: (1) PURPA and purchased
20 power expenses are classified as demand-and energy-related
21 in the same manner as steam and hydro generation plant and
22 (2) the energy-related cost allocators, "E10S" and "E10NS,"
23 are derived using an averaging approach. In addition to
24 incorporating the changes applied in the Modified Base

1 Case, the 3CP/12CP study further modifies the Base Case
2 study by allocating the costs of the Company's generation
3 peaking facilities differently than its base-load
4 resources. I will describe each study in greater detail
5 later in my testimony.
6 Q. Other than the changes to the preparation of
7 the coincident peak demand values described earlier, does
8 the Base Case cost-of-service study apply the same
9 methodology used to prepare the cost-of-service study in
10 the 03-13 Case?
11 A. Yes. While the accounting data and other
12 inputs to the model have been updated to align with the
13 2008 test year, the overall methodology, with the changes I
14 described earlier, is consistent with that applied in the
15 03-13 Case.
16 Q. Have you incorporated any changes into the
17 cost-of-service methodology to better reflect the ways in
18 which costs are currently imposed on the Company's system?
19 A. Yes. The two additional studies prepared as
20 part of this general rate case proceeding, the Modified
21 Base Case study and the 3CP/12CP study, incorporate a
22 number of changes to the Base Case cost-of-service
23 methodology in an effort to better reflect the ways in
24 which costs are currently imposed on the Company's system.

1 Q. How does the allocation approach used under
2 the Modified Base Case study differ from the methodology
3 used in the Base Case?
4 A. The Modified Base Case study differs from
5 the Base Case study in the manner in which PURPA and
6 purchased power expenses are classified as demand-and
7 energy-related. Under the Modified Base Case study, PURPA
8 and purchased power expenses booked to FERC Account 555 are
9 classified as demand-and energy-related in the same manner
10 as steam and hydro generation plant. In addition, the
11 energy-related cost allocators, E10S and E10NS, are derived
12 by averaging the normalized energy values for each customer
13 class with the normalized energy values weighted by the
14 marginal energy costs.
15 Q. On what basis has the Company historically
16 classified PURPA and Purchased Power expenses booked to
17 FERC Account 555?
18 A. FERC Account 555 has historically been
19 classified as either demand-related or energy-related
20 according to an "as-billed basis." That is, purchased
21 power expenses are classified as either demand- or energy-
22 related based upon the structure of the power purchase
23 contract between the Company and the energy seller. FERC
24 Account 555 has two sub-accounts: 555.1, Purchased Power

1 (non-PURPA purchases), and 555.2, Cogeneration and Small
2 Power Production (PURPA purchases). Sub-account 555.1,
3 Purchased Power, has historically been classified as
4 "energy only" to align with the structure of the purchase
5 agreements. Sub-account 555.2, Cogeneration and Small
6 Power Production, has, in recent years, been classified as
7 approximately 95 percent energy and approximately 5 percent
8 demand.
9 Q. How did the Company arrive at the 95 percent
10 to 5 percent split between energy and demand for sub-
11 account 555.2?
12 A. Prior to July 1983, each cogeneration and
13 small power production agreement contained both a capacity
14 and energy payment component. The Commission's Order No.
15 18190, issued July 21, 1983, directed the Company to
16 restructure its cogeneration and small power project rates
17 to include only an energy-based component. The demand-
18 related dollar value booked to Account 555.2 represents the
19 sum of the fixed capacity payments agreed to under the
20 active contracts executed prior to the issuance of Order
21 No. 18190, with the remainder of sub-account 555.2 being
22 classified as energy.
23 Q. Why do you believe that it is appropriate to
24 classify a larger share of the Company's Purchased Power

1 expenses booked to FERC Account 555 as demand-related?

2 A. The Company's purchased power expenses have

3 grown in recent years to represent a larger share of the

4 overall revenue requirement. This growth in purchased

5 power expenses has occurred as market purchases and PURPA

6 projects have become further integrated into the Company's

7 resource portfolio. For example, in 2007, purchased power

8 was the source approximately 28 percent of the Company's

9 system-wide energy sales. With that in mind, it seems

10 reasonable to begin to classify a larger portion of FERC

11 Account 555 as demand-related.

12 Q. Why are you recommending to classify

13 Purchased Power expenses booked to FERC Account 555 as

14 demand- and energy-related in the same manner as steam and

15 hydro generation plant?

16 A. As I stated earlier, market purchases and

17 PURPA projects continue to represent an increasingly larger

18 share of the Company's resource portfolio. Under the

19 traditional approach of classifying these expenses as

20 energy only, customers who use a larger proportion of

21 energy with respect to their demand (higher load factors)

22 receive a greater allocation of these expenses than would

23 have occurred if a power plant had been constructed to

24 serve the same loads. For example, if the Company had

1 chosen to build and operate a power plant to serve the same
2 customer loads served by purchased power, the plant would
3 have been classified as both demand and energy. With that
4 said, it seems reasonable to classify these expenses as
5 demand- and energy-related in the same manner as the
6 Company's steam and hydro generation plant.
7 Q. How does the allocation approach used under
8 the 3CP/12CP differ from the methodology used in prior rate
9 case proceedings?
10 A. The 3CP/12CP study builds upon the revised
11 classification methodology applied in the Modified Base
12 Case by allocating production plant costs based on the
13 nature of the load being served. Under this approach,
14 production plant costs associated with serving summer peak
15 load are allocated separately from costs associated with
16 serving the base and intermediate load. That is, the costs
17 associated with building and operating combustion turbines,
18 which are used primarily to serve summer peak loads, have
19 been allocated to customers differently than the costs
20 associated with the Company's other generation resources.
21 Q. On what basis has the Company historically
22 allocated its fixed generation costs?
23 A. Historically, Idaho Power has allocated all
24 fixed generation costs based on the average of the twelve

1 monthly coincident peaks weighted by the monthly marginal
2 generation cost. This historical approach has attempted to
3 incorporate a forward-looking component into the current
4 costs through the use of marginal cost weighting. This
5 method has been effective in allocating costs to customer
6 classes based on peak demand during the higher cost months.
7 However, there is potential to disproportionately allocate
8 fixed base and intermediate generation costs that do not
9 vary greatly between the summer and non-summer seasons to
10 the higher cost summer months.
11 Q. Does the 3CP/12CP approach reduce the
12 potential to disproportionately allocate fixed base and
13 intermediate generation costs that do not vary greatly
14 between the summer and non-summer seasons to the higher
15 cost summer months?
16 A. Yes. The 3CP/12CP method allocates
17 production plant costs associated with serving base and
18 intermediate load using an average of 12 monthly coincident
19 demands ("12CP"), without marginal cost weighting. Using
20 an un-weighted 12CP allocator is more appropriate in this
21 case given that fixed base and intermediate generation
22 costs do not vary greatly between the summer and non-summer
23 seasons. Furthermore, the 3CP/12CP study allocates fixed
24 generation costs associated with serving peak load using an

1 average of the three coincident peak demands ("3CP")
2 occurring in June, July, and August. This method of
3 allocation isolates the costs associated with peaking
4 resources and allocates those costs according to the load
5 that is causing the investment.
6 Q. How did you arrive at the two cost
7 categories of base/intermediate and peak used in the
8 3CP/12CP study?
9 A. The cost allocation method used in the
10 3CP/12CP study is based on the concept that the costs
11 associated with each of the Company's generation resources
12 can be categorized according to the type of loads being
13 served. Utilities typically experience three distinct
14 time-based production costing periods that are driven by
15 customer loads. The costing periods are normally
16 identified as base, intermediate, and peak. The base
17 period is equivalent to a low load or off-peak time period
18 where loads are at the lowest, normally during the
19 nighttime hours. The intermediate time period represents
20 the shoulder hours which are driven by the mid-peak loads
21 that typically occur throughout the winter daytime and in
22 the early morning and late evening during the summer
23 months. The peak category is driven by the peak loads that
24 occur during summer afternoons and evenings. The base and

1 intermediate loads on Idaho Power's system are typically
2 served by than same generation resources. In recognition
3 of that fact, those two categories have been combined for
4 cost allocation purposes. The generation resources that
5 serve the peak loads, i.e., combustion turbines, are
6 normally only utilized for that single purpose. Consistent
7 with that concept, the costs associated with peak-related
8 resources have been segmented into a second category for
9 cost allocation purposes.
10 Q. Please explain how production plant costs
11 have been classified as serving base and intermediate load.
12 A. The production plant costs that have been
13 classified as serving base and intermediate load are
14 captured in Accounts 310-316, Steam Production, and
15 Accounts 330-336, Hydraulic Production. The costs
16 identified under the Steam Production category represent
17 the Company's investment in the coal-fired generation
18 facilities. The costs identified under the Hydraulic
19 Production category represent the Company's investment in
20 its hydroelectric generation facilities.
21 Q. How does the Company utilize its steam and
22 hydro resources to serve both base and intermediate loads?
23 A. Utilities typically utilize their generation
24 resources to serve customer loads by operating the

1 resources with the lowest operating cost first and as
2 demand grows more costly resources are then dispatched.
3 This is no different for Idaho Power. However, since
4 hydroelectric generation is such a significant portion of
5 the Company's resource stack, stream flow conditions as
6 well as economics can influence the proportionate share of
7 output provided by steam and hydro resources throughout the
8 year. Since hydroelectric output is highly dependent upon
9 stream flows, steam production is ramped up or down
10 according to the production capability of the hydro.
11 Therefore, throughout the year, hydro and steam production
12 plants are utilized at varying proportions to serve base
13 and intermediate loads according to the production
14 capabilities of the hydro plants. However, the combined
15 monthly output of these two resource types does not vary
16 significantly between the summer and non-summer months as
17 does the output of the combustion turbines.
18 Q. How do you propose to identify the fixed
19 generation costs associated with serving the peak load?
20 A. Accounts 340-346, Other Production, contain
21 the Company's investment in gas-fueled production plant.
22 The production plant investment captured in Accounts 340-
23 346 represents the Company's investment in the combustion
24 turbine generation facilities used to serve peak demands.

1 Q. Have you attempted to identify any other
2 production plant used to serve summer peak demands that is
3 not booked to Accounts 340-346?
4 A. No. I have simply identified as peaking
5 plant the investment in combustion turbine generation
6 resources that were constructed specifically to meet the
7 summer peak loads.
8 Q. Are the cost allocation modifications
9 proposed in the 3CP/12CP cost-of-service study, as compared
10 to the Modified Base Case, focused solely on the allocation
11 of generation costs?
12 A. Yes. In recent years, the Company's system
13 peak has grown at a much faster pace than average demand, a
14 trend that is expected to continue into the future. For
15 example, a comparison of Figures 4-1 and 4-2 on pages 39
16 and 40 of the 2006 IRP (included in my workpapers) will
17 show, that by 2012, the Company expects an energy
18 deficiency in July of approximately 150 aMW with a peak
19 hour deficiency of almost 600 MW in the same month. In
20 response to the changing system load profile, combustion
21 turbines have been added as a cost-effective means to serve
22 peak load. This shift in resource mix has caused the
23 Company to investigate alternative methods for allocating
24 generation costs.

1 Q. The Company's investment in transmission and
2 distribution facilities has also grown in recent years. Is
3 there a need to adjust the allocation method for those
4 functional categories?
5 A. No. The Company's historical approach to
6 cost allocation for transmission and distribution
7 facilities is an effective method for equitably assigning
8 costs to customer classes during periods of growth. Under
9 the historical allocation method, transmission and
10 distribution costs are properly segmented according to the
11 manner in which the costs are imposed on the system. As a
12 result, the cost responsibility of each class can be
13 effectively identified through a combination of direct cost
14 assignment and cost allocation based on the appropriate
15 demand- or customer-based factors.
16 Q. Have you prepared a table that describes how
17 the allocation approaches vary among the three cost-of-
18 service studies submitted as part of this proceeding?

A. Yes. The following table is an illustration of the general similarities and differences between the three studies:

Functional Category	Base Case	Modified Base Case	3CP/12CP
Classification			
Generation Plant			
Hydro and Steam Production	59.38% Energy & 40.62% Demand	Same as Base Case	Same as Base Case
Other Production (Peaking Units)	Demand	Same as Base Case	Same as Base Case
Transmission Plant	Demand	Same as Base Case	Same as Base Case
Distribution Plant	Demand and Customer	Same as Base Case	Same as Base Case
Other Expenses			
Fuel	Energy	Same as Base Case	Same as Base Case
Purchased Power	Energy (< 3% Demand)	59.38% Energy & 40.62% Demand	59.38% Energy & 40.62% Demand
Allocation			
Generation Demand			
Hydro and Steam Production	12CP with Marginal Generation Cost Weighting	Same as Base Case	12CP without Marginal Generation Cost Weighting
Other Production (Peaking Units)	12CP with Marginal Generation Cost Weighting	Same as Base Case	3CP without Marginal Generation Cost Weighting
Generation Energy	12 Months Energy with Marginal Energy Cost Weighting	12 Months Energy with Marginal Energy Cost Weighting (averaged w/ un-weighted values)	12 Months Energy with Marginal Energy Cost Weighting (averaged w/ un-weighted values)
Transmission	12CP with Marginal Transmission Cost Weighting	Same as Base Case	Same as Base Case
Distribution	1NCP / No. of Customers / Direct Assignment	Same as Base Case	Same as Base Case

Q. Do you plan to cover each of the three cost-of-service studies in equal detail as part of your testimony?

A. No. Because all three studies are quite similar in their overall structure, I will cover the Base Case study in greater detail and simply describe how the other studies differ from the Base Case.

BASE CASE COST-OF-SERVICE STUDY DESCRIPTION

Q. Please identify the exhibits that comprise the Base Case cost-of-service study.

A. The Base Case cost-of-service study is comprised of the following exhibits:

Exhibit	Description
Exhibit No. 53	Functionalization and Classification of Costs
Exhibit No. 54	Summary of Functionalized Costs
Exhibit No. 55	Allocation to Classes
Exhibit No. 56	Summary of Class Allocations
Exhibit No. 57	Revenue Requirement Summary
Exhibit No. 58	Class Cost-of-Service Unit Costs
Exhibit No. 59	Development of Weighted Demand and Energy Allocators

Q. Please describe Exhibit No. 53.

A. Exhibit No. 53 contains 130 pages and consists of 11 Cost Functionalization and Classification Tables. The functionalization and classification of each component of rate base, operating revenue, and expense are treated in detail in these tables. The tables are shown in

the following sequence:

Table No.	Description
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	Regulatory Debits/Credits
9	Income Taxes
10	Development of Labor-Related Allocator
11	Functionalization Allocators

Q. What is the significance of the column headed "Allocator" on Exhibit No. 53?

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 production function and to the demand and energy cost classifications. The resultant functionalization of costs may itself serve as a basis for

1 subsequent allocations. This use is illustrated at line
2 115 on page 16 where the accumulated depreciation for steam
3 production plant is allocated according to the same
4 allocator "PI-S" used at line 20.
5 Q. Please describe the classification of plant
6 utilized in the Base Case cost-of-service study.
7 A. In the class cost-of-service study all steam
8 and hydro production plants have been classified on a
9 demand and energy basis using the methodology preferred by
10 the Commission in prior general rate proceedings. The
11 energy portion of the steam and hydro production investment
12 has been determined by use of the Idaho jurisdictional load
13 factor of 59.38 percent. The computation of the Idaho
14 jurisdictional load factor is included in my workpapers.
15 By application of the load factor ratio to the steam and
16 hydro production plant investment, the energy-related
17 portion is easily determined. The balance of the steam and
18 hydro production plant investment is then classified as
19 demand-related. All other production and transmission
20 plants have been classified as demand-related.
21 Q. Would you describe how distribution plant
22 has been classified?
23 A. Distribution substation plant, Accounts 360,
24 361, and 362, has been classified as demand-related.

1 Distribution plant Accounts 364, 365, 366, 367, and 368
2 were classified as either demand-related or customer-
3 related using the same fixed and variable ratio computation
4 method utilized in the Company's prior general rate case
5 proceedings. The fixed to variable ratio has been updated
6 according to a system capacity utilization measurement
7 based on a three-year average (2005-2007) load duration
8 curve that is detailed in my workpapers.
9 Q. Would you please describe the
10 functionalization of general plant?
11 A. General plant was functionalized based on
12 total production, transmission, and distribution plant. As
13 a result, a portion of general plant was assigned to each
14 production, transmission, and distribution function based
15 on each function's proportion to the total.
16 Q. How was the accumulated provision for
17 depreciation functionalized?
18 A. The accumulated provision for depreciation
19 was functionalized using the resulting functionalization of
20 costs for the appropriate plant item. For example, the
21 accumulated depreciation for steam production plant shown
22 at line 115 on page 16 is functionalized based on the
23 functionalization of steam production plant in service at
24 line 20.

1 Q. Please describe Table 3 of Exhibit No. 53.

2 A. Table 3 indicates the functionalization of

3 all other additions to and deductions from rate base.

4 Deductions from rate base include customer advances for

5 construction and accumulated deferred income taxes.

6 Customer advances have been functionalized based on the

7 distribution plant investment against which the advances

8 apply. Accumulated deferred taxes have been functionalized

9 based on total plant investment. Additions to rate base

10 consist of fuel inventory, which has been functionalized

11 based on energy production, and materials and supplies,

12 which have been functionalized based on the appropriate

13 plant function. Deferred conservation expenses have been

14 functionalized based on the Idaho jurisdictional load

15 factor resulting in 59.38 percent of the deferred expenses

16 being functionalized to energy production and the remainder

17 being functionalized to demand production.

18 Q. Please describe the functionalization of

19 other operating revenue shown on Table 4 of Exhibit No. 53.

20 A. Other operating revenue is functionalized

21 based on either the functionalization of the related rate

22 base item or, in the situation where a particular revenue

23 item may be identified with a specific service, the

24 functionalization of the specific service item.

1 Q. Briefly describe the method by which
2 operation and maintenance expenses were functionalized.
3 A. The functionalization of operation and
4 maintenance expenses is detailed on Table 5 of Exhibit No.
5 53. In general, the basis for the functionalization may be
6 readily interpreted from the exhibit, particularly because,
7 in most cases, the functionalization is the same as that
8 for the associated plant.
9 Q. How is supervision and engineering expense
10 treated throughout the allocation of operation and
11 maintenance expenses?
12 A. For each applicable expense account in each
13 functional group, the labor component is separately
14 functionalized in accordance with the detail provided on
15 Table 10 of Exhibit No. 53. Referring to pages 91 through
16 105 of Table 10, it can be seen that the total of allocated
17 labor in each functional group becomes the basis for the
18 functionalization of supervision and engineering expense.
19 For example, for Account 535 at line 675, the labor-related
20 supervision and engineering expense is functionalized based
21 on lines 676-680 which represent the cumulative labor as
22 functionalized for Accounts 536 through 540 shown on page
23 91 of Exhibit No. 53. In a similar fashion, the allocation
24 of supervision and engineering associated with hydraulic

1 maintenance expense, Account 541, is based on the composite
2 labor expense for Accounts 542 through 545, as expressed by
3 lines 683-686. Total functionalized labor expense serves
4 the additional purpose of functionalizing employee pensions
5 and other labor-related taxes and expenses. Table 10
6 details the development of all labor-related
7 functionalization factors used in this study.
8 Q. Please describe the functionalization of
9 depreciation expense, taxes other than income, and income
10 taxes shown on Tables 6, 7, 8, and 9, respectively.
11 A. Depreciation expense is functionalized based
12 on the function of the associated plant. Taxes other than
13 income are also functionalized based on the function of the
14 source of the tax. Deferred income taxes are
15 functionalized based on plant investment. The
16 functionalization of federal and state income taxes is
17 based on the functionalization of total rate base and
18 expenses and is discussed in more detail in my testimony
19 regarding the allocation of costs to classes of customers.
20 Q. Please describe Exhibit No. 54.
21 A. Exhibit No. 54 summarizes in row format the
22 functionalized costs for each component of rate base and
23 expenses shown across the columns on Exhibit No. 53.
24 Q. Please describe Exhibit No. 55.

A. Exhibit No. 55 details the allocation of the summarized costs shown on Exhibit No. 54 to each customer class, 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	Substation CIAC
5	Customer Advances for Construction
6	Accumulated Deferred Income Taxes
7	Acquisition Adjustment
8	Working Capital
9	Deferred Programs
10	Subsidiary Rate Base
11	Plant Held for Future Use
12	Other Revenues
13	Operation & Maintenance Expenses
14	Depreciation Expense
15	Amortization of Limited Term Plant

Table No.	Description
16	Taxes Other Than Income
17	Regulatory Debits/Credits
18	Provisions for Deferred Income Taxes
19	Investment Tax Credit Adjustment
20	Construction Work In Progress
21	State Income Taxes
22	Federal Income Taxes
23	Allocation Factor Summary

Q. Briefly describe the manner in which you allocated the summarized costs shown on Exhibit No. 54 to each class of service as shown on Tables 1 through 22 of Exhibit No. 55.

A. The demand-related generation and transmission costs have been allocated to customer classes based on a methodology that incorporates both actual and marginal-cost-weighted coincident peak demands. The energy-related generation costs have been allocated to customer classes based on a methodology that incorporates both actual and marginal-cost-weighted normalized monthly energy consumption.

Q. What is the reasoning for using marginal cost weightings in the derivation of the demand- and

1 energy-related allocation factors?

2 A. The use of marginal cost weighting strikes a
3 balance between backward-looking costs already incurred and
4 forward-looking costs to be incurred in the future. This
5 approach injects into the allocation process recognition of
6 the influence seasonal load profiles have on cost
7 causation.

8 Q. Please describe the methodology used to
9 derive the demand-related allocation factors used to
10 allocate generation costs in the Base Case study.

11 A. The demand-related factors used to allocate
12 generation costs were derived using the same methodology as
13 that used since the Company's 03-13 Case. First, ratios
14 based on the sum of the actual coincident peak demands for
15 both the summer and non-summer seasons were calculated for
16 each customer class. Second, weighted coincident peak
17 demand values were derived by multiplying the actual
18 monthly coincident peak demands by the monthly marginal
19 costs. Corresponding ratios for both the summer and non-
20 summer seasons were then calculated for each customer
21 class. Finally, the actual summer and non-summer ratios
22 were averaged with the weighted summer and non-summer
23 ratios to derive the demand-related allocators D10S and
24 D10NS, respectively. These factors where used to allocate

1 demand-related generation costs to the customer classes.

2 Q. Have the generation capacity marginal costs

3 used in the current study been updated since the Company's

4 previous study in Case No. IPC-E-07-08?

5 A. Yes. The generation capacity marginal

6 costs have been updated to reflect the costs associated

7 with the Danskin CT1 Combustion Turbine which came on line

8 in 2008. The generation capacity marginal cost was

9 seasonalized based on the monthly peak-hour generation

10 deficiencies which the Company expects to encounter during

11 the next five years of the planning period based on the 90th

12 percentile water and 70th percentile load criteria used for

13 planning purposes. These deficiencies are detailed on page

14 78 of the 2006 IRP Technical Appendix. I have included a

15 copy of this page in my workpapers. During the first five

16 years (2008 through 2012) of the remaining planning period

17 covered by the IRP, the months in which peak-hour deficits

18 exist are May, June, July, August, September, and December.

19 The relative sizes of the five-year average monthly

20 deficiencies were used to define the share of the annual

21 capacity cost assigned to each month.

22 Q. How were the demand-related transmission

23 marginal costs determined?

1 A. The transmission marginal costs reflect the
2 costs associated both with the integration of new resources
3 into the system and with the planned system expansions
4 needed to maintain reliable service as the Company's loads
5 continue to grow, combined with the Hemingway-Boardman
6 Capacity Upgrade. The marginal costs associated with the
7 new resource integration were seasonalized based on the
8 same methodology used for generation capacity; that is, the
9 relative sizes of the five-year average monthly peak-hour
10 deficiencies identified in the 2006 IRP were used to define
11 the share of the annual capacity cost assigned to each
12 month. The marginal costs associated with the planned
13 system expansions and Hemingway-Boardman Upgrade were
14 seasonalized based on the monthly share of the projected
15 peak-hour load growth. The total demand-related
16 transmission marginal costs for each month were then
17 derived by adding the monthly values for both categories of
18 transmission costs.
19 Q. What factor was used to allocate
20 transmission costs to the customer classes?
21 A. The allocation factor D13 was used to
22 allocate transmission costs to customer classes. This
23 factor was derived using the same methodology as that used
24 in the Company's previous general rate case. First, ratios

1 based on the sum of the actual coincident peak demands were
2 calculated for each customer class. Second, weighted
3 coincident peak demand values were derived by multiplying
4 the actual monthly coincident peak demands by the monthly
5 transmission marginal costs. Corresponding weighted ratios
6 were then calculated for each customer class. Finally, the
7 actual ratios were averaged with the weighted ratios to
8 derive the non-seasonalized transmission allocation factor
9 D13.
10 Q. Please describe the methodology used to
11 derive the energy-related allocation factors.
12 A. The energy-related allocation factors, E10S
13 and E10NS, were derived through a two-step process. First,
14 summer and non-summer ratios based on each class's
15 proportionate share of the total normalized energy usage
16 for the test year were determined. Next, summer and non-
17 summer ratios based on the monthly normalized energy usage
18 for each customer class weighted by the monthly marginal
19 cost were calculated. This is the same method used to
20 derive the E10S and E10NS allocators in Case No. IPC-E-03-
21 13.
22 Q. Have the generation energy marginal costs
23 used in the current study to derive the E10S and E10NS
24 allocation factors been updated since the Company's

1 previous study in Case No. IPC-E-07-08?

2 A. Yes. Updated marginal energy costs were

3 calculated by quantifying the difference in net power

4 supply costs resulting from the addition of 50 megawatts of

5 load to all hours of the Company's base case system

6 simulation run for the five-year period 2008 through 2012.

7 Q. Have you included information regarding the

8 derivation of the Company's updated marginal costs with

9 your testimony?

10 A. Yes. I have included a copy of the

11 Company's 2008 Marginal Cost Analysis in my workpapers.

12 Q. Have you prepared an exhibit that details

13 the derivation of the weighted demand and energy allocation

14 factors?

15 A. Yes. Exhibit No. 59 details the derivation

16 of the allocation factors D10S, D10NS, D13, E10S, and E10NS

17 used in the Base Case study.

18 Q. Have the marginal costs been used to develop

19 the Company's revenue requirement?

20 A. No. The marginal costs have been used

21 solely for purposes of developing allocation factors and

22 not for purposes of developing the Company's revenue

23 requirement.

1 Q. What was the method by which you allocated
2 costs associated with distribution plant included on
3 Exhibit No. 54 to each class of customers?
4 A. The capacity components of distribution
5 plant, both primary and secondary, were allocated by the
6 non-coincident group peak demands for each customer class
7 identified as demand allocation factors D20, D30, D50, and
8 D60. The customer components of distribution plant, both
9 primary and secondary, were allocated by the average number
10 of customers identified as customer allocation factors C20,
11 C30, C50 and C60.
12 Q. What was the method by which you allocated
13 costs associated with customer accounting and customer
14 assistance expenses?
15 A. The principal customer accounting expenses
16 which require allocation are meter reading expenses,
17 customer records and collections, and uncollectible
18 accounts. The meter reading and customer records and
19 collection expenses were allocated based upon a review of
20 actual practices of Idaho Power Company in reading meters
21 and preparing monthly bills. The allocation of
22 uncollectible amounts again was based upon a review of
23 actual Idaho Power Company data. Customer assistance
24 expenses were allocated based on the average number of

1 customers in each class.

2 Q. Does Exhibit No. 55 include a listing of the

3 allocation factors used to allocate to classes the various

4 costs shown on Tables 1 through 22?

5 A. Yes. Table 23 of Exhibit No. 55 includes a

6 listing of each allocation factor.

7 Q. How did you allocate state and federal

8 income tax to each customer class and special contract

9 customer as shown on Tables 21 and 22 of Exhibit No. 55?

10 A. The state and federal income taxes for the

11 Idaho jurisdiction, provided by Ms. Schwendiman, were

12 allocated to each customer class and special contract

13 customer according to each class's allocated share of rate

14 base. The worksheets showing this allocation are included

15 in my workpapers.

16 Q. What method was used to functionalize the

17 state and federal income taxes as shown on Table 21 and

18 Table 22 of Exhibit No. 55?

19 A. Once the state and federal income taxes were

20 allocated to each customer class, they were functionalized

21 based on the functionalization of total rate base and

22 expenses for each class. For example, the total summer

23 power supply production rate base amount of $70,613,133

24 allocated to the residential class on Tables 1 through 10

1 of Exhibit No. 55, and shown in summary form on page 1 of
2 Exhibit No. 55 at line 9, represents 7.46 percent of the
3 total rate base amount of $946,232,900 allocated to the
4 residential class. The state and federal income taxes
5 allocated to the residential class (<$1,655,018> and
6 $8,616,374, respectively) are multiplied by this same
7 percent to establish the summer power supply production
8 components of <$123,507> and $643,001 shown on Table 21 and
9 Table 22 of Exhibit No. 55. This same methodology is used
10 for all functional components and customer classes shown on
11 Tables 21 and 22.
12 Q. Please describe Exhibit No. 57.
13 A. Exhibit No. 57 is the revenue requirement
14 summary based on the results of the Base Case class cost-
15 of-service study. The section headed "Revenue Requirement
16 for Rate Design" details the sales revenue required from
17 each customer class and special contract customer. The
18 sales revenue required includes return on rate base, total
19 operating expenses, and incremental taxes computed using
20 the net-to-gross multiplier of 1.642 provided to me by Ms.
21 Schwendiman.
22 Q. Please describe Exhibit No. 57.
23 A. Exhibit No. 57 shows the unit cost for each
24 function for metered service schedules as determined

through the Base Case 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.

MODIFIED BASE CASE COST-OF-SERVICE STUDY

Q. Please describe how the model inputs under Modified Base Case study scenario differ from those used in the Base Case study.

A. As I mentioned earlier in my testimony, the Modified Base Case scenario is identical to the Base Case study with the exception that (1) PURPA and purchased power expenses are classified as demand-and energy-related in the same manner as steam and hydro generation plant and (2) the energy-related cost allocators, E10S and E10NS, are derived using an averaging approach.

Q. What portion of PURPA and purchased power expenses were classified as demand-related and what portion were classified as energy-related under the Modified Base Case?

A. Under the Modified Base Case, PURPA and purchased power expenses were classified as 40.62 percent demand-related and 59.38 percent energy-related, the same ratio of demand to energy used in the classification of hydro and steam generation plant.

1 Q. In the Base Case study, the energy
2 allocators E10S and E10NS were derived using a two-step
3 process under which summer and non-summer ratios based on
4 the monthly normalized energy usage for each customer class
5 were weighted by the monthly marginal cost. How do the
6 E10S and E10NS energy allocators differ under the Modified
7 Base Case study?
8 A. In the Modified Base Case study, a third
9 step was added by which the un-weighted summer and non-
10 summer ratios were averaged with the summer and non-summer
11 ratios weighted by the monthly marginal cost to derive the
12 summer and non-summer energy-related allocation factors
13 E10S and E10NS, respectively.
14 Q. Have you prepared an exhibit that details
15 the derivation of the energy-related allocation factors
16 E10S and E10NS used in the Modified Base Case study?
17 A. Yes. Exhibit No. 60 details the derivation
18 of the both the demand- and energy-related allocation
19 factors used in the Modified Base Case study, including
20 E10S and E10NS.
21 Q. What is your rationale for moving to the
22 "averaging approach" in the derivation of the E10S and
23 E10NS energy allocators?

A. The "averaging approach" is consistent with the methodology used in the derivation of the demand-related allocation factors that receive marginal cost weighting. That is, the D10s, D10NS, and D13 allocation factors used in the Base Case and Modified Base Case are all derived under the same averaging methodology. In the 05-28 Case and the last general rate case proceeding, Case No. IPC-E-07-08, the Company began applying the "averaging approach" as a rate stability measure intended to mitigate any extreme impacts that the marginal costs may have on cost allocation. However, in this case, the relative differences between the factors produced under either method are quite small and, therefore, have little impact on the resulting cost allocation.

3CP/12CP Cost-Of-Service Study

Q. Have you prepared any exhibits that detail the 3CP/12CP cost-of-service study?

A. Yes. The 3CP/12CP cost-of-service study is comprised of the following exhibits:

Exhibit	Description
Exhibit No. 62	Functionalization and Classification of Costs
Exhibit No. 63	Summary of Functionalized Costs
Exhibit No. 64	Allocation to Classes

Exhibit	Description
Exhibit No. 65	Summary of Class Allocations
Exhibit No. 66	Revenue Requirement Summary
Exhibit No. 67	Class Cost-of-Service Unit Costs
Exhibit No. 68	Development of Demand and Energy Allocators

Q. Please describe how 3CP/12CP study the model inputs differ from those used in the Base Case study.

A. As I mentioned earlier in my testimony, the 3CP/12CP study deviates from the Base Case methodology in the same manner as the Modified Base Case. In addition the 3CP/12CP cost-of-service study applies a different approach to allocating production plant costs.

Q. What are the demand-related allocation factors for production plant used in the 3CP/12CP study?

A. The derivation of the demand and energy allocators used in the 3CP/12CP scenario are shown on Exhibit No. 68. In order to avoid confusion among the various factors used in the model, I have used the names "D10BS" and "D10BNS" to describe the factors used to allocate the production plant associated with serving the base and intermediate loads. The name "D10P" is used to describe the allocation factor used to allocate the production plant associated with serving the peak loads.

1 Q. How were the demand-related allocation
2 factors for the 3CP/12CP study derived?
3 A. As can be seen in Exhibit No. 68, the D10BS
4 and D10BNS represent the non-weighted average twelve
5 coincident peak demands for the summer and non-summer
6 seasons respectively. The allocator D10P represents the
7 non-weighted average three coincident peak demands for the
8 summer months of June, July, and August. The allocators
9 for transmission plant and the energy allocators are the
10 same as those used in the Modified Base Case study.
11 Q. Why did you choose to derive the D10BS,
12 D10BNS, and D10P allocation factors with no marginal cost
13 weighting?
14 A. The segmentation of production plant costs
15 into base/intermediate and peak allows for a cost
16 allocation approach that recognizes the seasonality of the
17 loads associated with each category of investment.
18 Therefore, there is no need for marginal cost weighting
19 because the seasonal nature of the loads is reflected in
20 the allocation factors.
21 Q. How does this approach differ from that used
22 for the Base Case?
23 A. Under the Base Case approach, all production
24 plant costs, which include base, intermediate, and peak,

are allocated using the same allocation factors, i.e., D10S and D10NS. In the Base Case, the marginal cost weighting is applied to provide a seasonal recognition to cost causation similar to that automatically recognized through the "3CP" studies.

COMPARISON OF THE STUDY RESULTS

Q. How do the results from the Modified Base Case study compare with the results from the Base Case study?

A. The classification of PURPA and purchased power expenses as demand- and energy-related in the same manner as steam and hydro generation plant and the application of the energy-related cost allocators derived under an "averaging approach" result in a higher revenue requirement for Residential Service and Irrigation Service and a lower revenue requirement for all other customer classes, including the special contract customers, as compared to the Base Case. The Summary of Revenue Requirement for this scenario, which details the revenue requirement for each customer class, is included as Exhibit No. 61.

Q. How do the results from the 3CP/12CP study compare to the results from the Base Case study?

1 A. The results from the 3CP/12CP scenario are
2 shown on Exhibit No. 66. The results from the Base Case
3 study are shown on Exhibit No. 57. As can be seen from
4 comparing these two exhibits, the 3CP/12CP results indicate
5 a higher revenue requirement for Residential Service, Small
6 General Service, and Traffic Control Lighting and a
7 slightly lower revenue requirement for all other service
8 schedules and special contract service than do the results
9 of the Base Case.
10 Q. Are there any similarities in the results
11 among the three cost-of-service studies that you have
12 performed as part of this proceeding?
13 A. Yes. Although the absolute values are
14 different, the results from all three studies indicate that
15 the Large Power Service (Schedule 19), Irrigation Service
16 (Schedule 24), Traffic Control Lighting Service (Schedule
17 42), and special contract (Micron, Simplot, and DOE)
18 customers should have an increase in rates which is greater
19 than the overall average increase requested by the Company.
20 In addition, the results indicate that Dusk-to-Dawn
21 Customer Lighting Service (Schedule 15), Unmetered General
22 Service (Schedule 40), and Street Lighting Service
23 (Schedule 41) should have a decrease in rates from the
24 current level. Exhibit No. 69 includes in summary form the

1 results from all three cost-of-service studies.

2 Q. After reviewing the results of each study,

3 do you have a preferred cost-of-service approach?

4 A. Yes. The 3CP/12CP study applies my

5 preferred approach.

6 Q. Why is the 3CP/12CP study your preferred

7 approach to cost allocation?

8 A. Of the three studies, the 3CP/12CP study

9 applies an approach that results in the most equitable

10 allocation of costs to customer classes. Each study was

11 prepared with the same goal of allocating costs to customer

12 classes according to the cost impact that each class

13 imposes on the utility system. However, the 3CP/12CP study

14 applies a cost-of-service methodology that best reflects

15 the ways in which costs are currently imposed on the

16 Company's system. For example, over the last six years,

17 Idaho Power has added four combustion turbine generation

18 units to serve summer peak loads. Because the costs

19 associated with these new units are driven primarily by

20 summer loads, it is appropriate to allocate the cost of

21 those new resources according to each class's contribution

22 to the summer peak loads. However, production plant costs

23 associated with serving the base and intermediate loads are

24 driven more by the monthly peaks throughout the entire

1 year. By separating the production plant into the two
2 categories, the generation costs can be allocated according
3 to the most appropriate cost driver.
4 Q. Did you discuss all three studies internally
5 before deciding on your recommendation?
6 A. Yes. I arrived at my final recommendation
7 after discussing the results of each of the three studies
8 with Mr. Gale. Following that discussion, I provided the
9 class cost-of-service unit costs, detailed on Exhibit No.
10 67, to Ms. Waites, Ms. Nemnich, and Ms. Bowman for their
11 use in determining the component charges for each service
12 schedule.
13 **REVENUE REQUIREMENT ALLOCATION**
14 Q. What is the Company's general philosophy on
15 determining rates?
16 A. The Company's primary approach to ratemaking
17 in the last several general rate cases has been to
18 establish rates that reflect costs as accurately as
19 possible. Accordingly, the Company's ratemaking proposals
20 usually advocate movement towards cost-of-service results,
21 which assign costs to those customer classes that cause the
22 Company to incur the costs.
23 Q. Are there other objectives that may be
24 considered in the ratemaking process?

1 A. Yes. The Commission may consider a number
2 of other objectives, such as rate stability, rate shock,
3 and ability to pay in the determination of rates.
4 Q. How did you approach the determination of
5 the revenue requirement for each customer class?
6 A. A pure cost-of-service revenue spread would
7 result in substantial increases to Irrigation Service,
8 Large Power Service, Traffic Control Lighting Service, and
9 to the three special contract customers. In order to
10 mitigate the magnitude of the rate increase to each of
11 these customer classes that would be necessary to bring
12 them to current cost-of-service levels, the Company is
13 proposing to cap the percentage increase to those customer
14 classes at 15 percent or approximately one and one-half
15 times the average increase.
16 Q. Did you discuss the results of the cost-of-
17 service study internally before deciding to apply the 15
18 percent caps to the specified customer classes?
19 A. Yes. I discussed the results of the cost-
20 of-service study and potential rate spread scenarios with
21 Mr. Gale, who is responsible for the overall preparation of
22 this case. My revenue allocation recommendation is a
23 result of those discussions.

1 Q. Do you have an exhibit that details the
2 class revenue requirement determination?
3 A. Yes. Exhibit No. 70 is a four-page exhibit
4 that steps through the revenue requirement allocation
5 process from the cost-of-service results to the ultimate
6 proposal for each customer class. Page 1 of Exhibit No. 70
7 is the proformed normalized test year sales and revenues.
8 Page two details the results from the cost-of-service study
9 and illustrates the revenue changes that would be made to
10 each customer class to obtain the cost-of-service results.
11 Page three shows the revenue shortfall that resulted by
12 applying a 15 percent cap to the specified customer
13 classes. Finally, Page four shows the proposed increase to
14 the other customer classes which resulted from spreading
15 the shortfall created by the mitigation to the remaining
16 classes in order to obtain the total Idaho jurisdictional
17 target revenue requirement. I have provided the results
18 from Page four to Ms. Waites, Ms. Nemnich, and Ms. Bowman
19 for their use in determining the individual rates for the
20 Company's general tariff and special contract customers.
21 **FIXED COST ADJUSTMENT RATES**
22 Q. Please describe the Fixed Cost Adjustment
23 ("FCA") mechanism.

A. The FCA is a rate mechanism that is designed to remove the financial disincentive to utility acquisition of demand-side management resources. The mechanism accomplishes this goal by severing the link between energy sales and the recovery of fixed costs. Currently, the FCA applies only to Residential Service (Schedules 1, 4, and 5) and Small General Service (Schedule 7). The annual FCA amount is determined according to the following formula:

FCA = (CUST X FCC) - (NORM X FCE)

Where:

FCA = Fixed Cost Adjustment;

CUST = Actual number of customers, by class;

FCC = Fixed Cost per Customer, by class;

NORM = Weather-normalized energy, by class;

FCE = Fixed Cost per Energy, by class.

Q. What values are required to calculate the FCA amount annually?

A. As outlined in the above formula, for each class (Residential Service and Small General Service), the actual number of customers ("CUST"), the fixed cost per customer ("FCC"), weather-normalized energy ("NORM"), and the Fixed Cost per Energy ("FCE") are required to determine the FCA amount. Two of these variables (CUST and NORM) are determined at the end of each year based upon the Company's

1 actual billing records. The other two variables (FCC and
2 FCE) are updated each time the Company files a general rate
3 case and are based on the results of the class cost-of-
4 service study.
5 Q. Have you updated the FCC and FCE rates as
6 part of this general rate case proceeding?
7 A. Yes. Pursuant to Order No. 30556, I have
8 updated the FCC and the FCE rates using the functionalized
9 revenue requirement data resulting from the 3CP/12CP cost-
10 of-service study included on Exhibit No. 67. The updated
11 FCC and FCE rates have been included on the revised
12 Schedule 54, Fixed Cost Adjustment.
13 Q. Please describe the process used to
14 determine the FCC and FCE rates for the FCA mechanism,
15 which have been submitted as part of this general rate case
16 proceeding.
17 A. The FCC and FCE rates submitted as part of
18 this general rate case proceeding are based upon the 2008
19 test year. These rates most accurately represent the
20 Company's current fixed costs. Exhibit No. 71, Tables I,
21 II, and III detail the computational process that was used
22 to determine these class-specific fixed-cost amounts.
23 The first step in this process is a determination of
24 the 2008 test year fixed cost recovery embedded in the

1 energy charges for Residential Service and Small General
2 Service customers. As can be seen on Exhibit No. 71, Table
3 III, column J, for Residential Service, $179,439,869 of
4 fixed costs is to be recovered from the residential
5 customers through energy charges. For Small General
6 Service, $9,661,329 of fixed costs is to be recovered from
7 the energy charges.
8 Q. Do these fixed cost amounts for the
9 Residential and Small General Service customer classes
10 include more than their actual class cost of service?
11 A. Yes. There is a difference between the
12 class cost of service numbers and the amount of requested
13 revenue requirement. This difference is a result of the
14 cross-class subsidies that are currently present in the
15 Company's rate structure. The total cross-class subsidies
16 as well as the fixed cost portion of those subsidies are
17 identified on Exhibit No. 71, Table II.
18 Q. Why is it important to include these fixed
19 cost subsidies for the Residential and Small General
20 Service classes?
21 A. When fixed costs are recovered through a
22 volumetric rate, the effects of any conservation program
23 that reduces energy consumption results in a loss in the
24 recovery of those fixed costs. In the case of both the

1 Residential and Small General Service customer classes, the
2 reduction of energy consumption through conservation
3 measures not only prevents the Company from recovering the
4 fixed costs associated with those classes but, in addition,
5 prevents the fixed cost recovery of the subsidies which are
6 incorporated in their energy rates.
7 Q. How are the class-specific fixed cost
8 amounts established in the initial step used to derive the
9 updated FCC rates?
10 A. The determination of the FCC rate utilizes
11 the annual average number of customers for the Residential
12 customer class and Small General Service customer class.
13 As can be seen on Exhibit No. 71, Table III, column A, the
14 2008 average number customers is 391,057 for the
15 Residential customer class and 31,196 for the Small General
16 Service customer class.
17 With these two principal base level values, the FCC
18 rate can be determined. The annual fixed costs recovered
19 through the energy charges divided by the 2008 average
20 number of customers results in an annual fixed cost
21 recovery per customer, or the FCC rate, shown on Exhibit
22 No. 71, Table III, column K. For the Residential class,
23 the annual fixed cost recovery per customer is $458.86
24 ($179,439,869 / 391,057). For the Small General Service

1 class, the annual fixed cost recovery per customer is
2 $309.69 ($9,661,329 / 31,196).
3 Q. How are the class-specific fixed cost
4 amounts established in the initial step used to derive the
5 updated FCE values?
6 A. The determination of the FCE rate utilizes
7 the Residential and Small General Service weather-
8 normalized energy consumption for the 2008 test year
9 included on Exhibit No. 78. As can be seen on Exhibit No.
10 71, Table III, column B, the 2008 weather-normalized annual
11 energy consumption for the Residential customer class is
12 5,065,086,947 kWh and annual energy consumption for the
13 Small General Service class is 190,586,226 kWh.
14 With these additional principal base level values,
15 the FCE rate can be determined. The annual fixed cost
16 recovered through the energy charges divided by the
17 normalized energy results in an annual fixed cost recovery
18 per kWh, or the FCE rate, shown on Exhibit No. 71, Table
19 III, column L. For the Residential class, the fixed cost
20 recovery per kWh is $0.035427 ($179,439,869
21 /5,065,086,947). For the Small General Service class, the
22 annual fixed cost recovery per kWh is $0.050693
23 ($9,661,329/190,586,226).

1 Q. Is the methodology used to establish the FCC
2 and FCE rates in this general rate case proceeding the same
3 as that used the last time the FCC and FCE rates were
4 updated in Case No. IPC-E-08-04?
5 A. Yes. However, this is the first time that
6 the Company has submitted the revised FCA-related values as
7 part of a general rate case proceeding.
8 Q. Does this conclude your testimony?
9 A. Yes, it does.