<u>Appendix 7.3 – Class Cost-of-Service Process Guide</u>

To help support the evaluation of the Class Cost-of-Service Process Guide, Idaho Power Company began with the guide previously provided as Larkin DI Testimony Exhibit No. 30 in IPC-E-11-08, Idaho Power Company's last rate case. The process guide is unchanged except to highlight new methodology since the 2011 rate case. All additions are denoted by two asterisks (**) at the start and end of the addition with added text in ***italicized, bold font****.*

The following is a technical description of Idaho Power Company's Class Cost of Service study. 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.

I. <u>PROCESS OVERVIEW</u>

A. <u>Classification</u>

The Electric Utility Cost Allocation Manual, published in January of 1992 by the National Association of Regulatory Utility Commissioners, serves as the basis for the Company's classification process. Classification refers to the identification of a 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 makes service available to customers on a continuous basis, provides as much service, or capacity, as the customer desires at any point in time, and supplies energy, which provides the customer 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 used by the customers.

Examples of customer-related costs are the plant investments and expenses that are associated with meters and service drops, meter reading, billing and collection, and customer information and services as well as a portion of the investment in the distribution system. These investments and expenses are made and incurred based on the number of customers, regardless of the amount of energy used, and are therefore generally considered to be fixed costs. Demand-related costs are investments in generation, transmission, and a portion of the 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. However, due to the hydro production capability of the Company, a portion of the hydro and thermal generating plant investment has historically been classified as energy-related.

B. Functionalization

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, such as substations, primary lines, secondary lines and meters. This level of functionalization allows costs to be more equitably allocated among classes of customers.

C. Allocation and Summarization of Results

Once costs have been classified and functionalized, they are allocated to rate classes based on the appropriate allocation factors. After individual costs have been allocated to the various classes of service, it is possible to total these costs as allocated and arrive at a breakdown of utility rate base and expenses 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.

II. ASSIGN MODULE AND FUNCTIONALIZED COST MODULE

The class cost-of-service model is comprised of two separate Microsoft Excel workbooks. The first workbook, called the Assign Module, performs the previously described classification and functionalization processes. This workbook categorizes the Idaho jurisdictional costs identified by FERC account into operating functions, such as production, transmission, distribution, metering, customer service, etc. It also categorizes the functional costs into demand-, energy-, and customer-related classifications. For example, the Assign Module categorizes the Company's investment in steam plant into the production function and the demand- and energy-related classifications.

The second workbook, called the Functionalized Cost Module, or "FC Module" for short, performs the class allocation process. This module allocates the classified and functionalized costs developed in the Assign Module to the various customer classes. For example, the FC Module allocates the demand- and energy-related production costs identified in the Assign Module to each of the Company's customer classes and special contract customers. Each of the major operations performed by this module is shown as a separate worksheet to make the allocation process transparent and easy to understand.

III. CLASSIFICATION

A. Steam and Hydro Production

In the class cost-of-service study all steam and hydro production plants have been classified on a demand and energy basis using the methodology preferred by the Idaho Public Utilities 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. 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 and transmission plants have been classified as demand-related.

*****One update from the Company's 2011 rate case is the addition of the Langley production plant, which is considered baseload production similar to steam production plants, thus it is classified with the same demand and energy allocation as steam production plants. For classification of costs related to all natural gas-fired production plants, a new allocation factor was developed reflecting the weighting of all gas-fired production.*****

B. PURPA and Purchased Power Expenses

PURPA and purchased power expenses booked to FERC Account 555 are classified as demand-and energy-related in the same manner as steam and hydro generation plant. Under the previous approach of classifying these expenses as energy only, customers who use a larger proportion of energy with respect to their demand (higher load factors) receive a greater allocation of these expenses than would have occurred if a power plant had been constructed to serve the same loads. For example, if the Company had chosen to build and operate a power plant to serve the same customer loads served by purchased power, the plant would have been classified as both demand and energy. With that said, it is reasonable to classify these expenses as demand- and energy-related in the same manner as the Company's steam and hydro generation plant. Under this methodology, PURPA and purchased power expenses are classified according to the same ratio of demand to energy used in the classification of hydro and steam generation plant.

C. Distribution Plant

Distribution substation plant Accounts 360, 361, and 362 are classified as demand-related. Distribution plant Accounts 364, 365, 366, 367, and 368 are classified as either demand-related or customer-related using the same fixed and variable ratio computation method utilized in the Company's prior general rate case proceedings. The fixed to variable ratio is updated according to a system capacity utilization measurement based on a three-year average load duration curve.

IV. FUNCTIONALIZATION

A. General Plant

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

B. Accumulated Provision for Depreciation

The accumulated provision for depreciation is functionalized using the resulting functionalization of costs for the appropriate plant item. For example, the accumulated depreciation for steam production plant shown is functionalized based on the functionalization of steam production plant in service.

C. Additions to and Reductions from Rate Base

Deductions from rate base include customer advances for construction and accumulated deferred income taxes. Customer advances are functionalized based on the distribution plant investment against which the advances apply. Accumulated deferred taxes are functionalized based on total plant investment. Additions to rate base consist of fuel inventory, which is functionalized based on energy production, and materials and supplies, which are functionalized based on the appropriate plant function. Deferred conservation expenses are functionalized based on the Idaho jurisdictional load factor resulting in a specific percentage of the deferred expenses being functionalized to energy production and the remainder being functionalized to demand production.

D. Other Operating Revenue

Other operating 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.

E. O&M Expense

In general, the basis for the functionalization of O&M expense is the same as that for the associated plant.

F. Labor Components

For each applicable expense account in each functional group, the labor component is separately functionalized. For example, for Account 535 the labor-related supervision and engineering expense is functionalized based on the cumulative labor as functionalized for Accounts 536 through 540. 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. Total functionalized labor expense serves the additional purpose of functionalizing employee pensions and other labor-related taxes and expenses.

G. Depreciation Expense, Taxes Other than Income, and Income Taxes

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 plant investment. The functionalization of federal and state income taxes is based on the functionalization of total rate base and expenses.

V. ALLOCATION

A. Derivation of Peak Demands

For customers taking service through interval meters, system coincident demands are taken directly from their meter read data. For all other customers coincident demands are estimated through the use of system coincident demand factors. These factors are defined as the ratio of the system coincident demand to the population's average demand. To determine the monthly system coincident peak demands by rate class, each class's monthly system coincident demand factors from the load research sample are applied to the test year monthly average demand values for each class. Similarly, a non-coincident (or "group") demand factor is defined as the ratio of a population's non-coincident peak demand to the population's average demand. To determine the monthly non-coincident peak demands by rate class, each class's monthly non-coincident demand factors from the load research sample are applied to the test year monthly average demand values for each class.

Customers are billed throughout each month and billing periods, or cycles, typically include portions of more than one calendar month. Billing period data is converted into calendar month data using a nonlinear method based on load research data that utilizes actual daily usage patterns. Total daily consumption is assumed to fluctuate in proportion to the fluctuations in the daily consumption of the load research sample customers. This methodology captures the effects of weather on energy consumption and improves the process of determining coincident peak demand responsibility.

*****System coincident peak demand allocates capacity costs required to serve Residential and Small General Service on-site generation customers drawing energy, and requires modification to the derivation of peak demand. For each of the two studies, Idaho Power utilized the respective measurement interval, hourly netted energy, or real-time delivered energy for Residential and Small Generation Service on-site generation customers to reflect the load service provided by Idaho Power at the time of system peak. Because the value for Residential and Small General on-site generation will be established independently through this docket, this adjustment is necessary to avoid the double counting of benefits related to excess generation at the time of system peak.*****

B. <u>Marginal Cost Usage</u>

While the 3CP/12CP methodology eliminates the need for marginal cost weighting in the allocation of production plant costs, this weighting is still necessary to properly seasonalize energy- and transmission-related costs. The use of marginal cost weighting strikes a balance between backward-looking costs already incurred and forward-looking costs to be incurred in the future, and injects into the allocation process recognition of the influence seasonal load profiles have on cost causation.

The marginal costs associated with new resource integration are seasonalized based on the monthly peak-hour generation deficiencies which the Company expects to encounter during the next five years of the planning period based on the 90th percentile water and 70th percentile load criteria used for planning purposes. The relative sizes of the five-year average monthly peak-hour deficiencies identified in the IRP are used to define the share of the annual capacity cost assigned to each month. The marginal costs associated with planned system expansions are seasonalized based on the monthly share of projected peak-hour load growth. The total demand-related transmission marginal costs for each month are then derived by adding the monthly values for both categories of transmission costs.

Updated marginal energy costs are calculated by quantifying the difference in net power supply costs resulting from the addition of 50 megawatts of load to all hours of the Company's base case system simulation run for the five-year planning period. It should be noted that the marginal costs have been used solely for purposes of developing allocation factors and not for purposes of developing the Company's revenue requirement.

C. <u>Production Plant Cost Allocation</u>

The class cost-of-service study allocates the costs of the Company's generation peaking facilities differently than its base-load resources. Rather than allocating all production plant based on the same allocation factor, this method allocates production plant costs based on the nature of the load being served. Under this approach, production plant costs associated with serving summer peak load are allocated separately from costs associated with serving the base and intermediate load. That is, the costs associated with building and operating combustion turbines, which are used primarily to serve summer peak loads, have been allocated to customers differently than the costs associated with the Company's other generation resources. This method allocates production plant costs associated with serving base and intermediate load using an average of 12 monthly coincident demands ("12CP"), without marginal cost weighting. Using an un-weighted 12CP allocator is appropriate in this case given that fixed base and intermediate generation costs do not vary greatly between the summer and non-summer seasons. Furthermore, the study allocates fixed generation costs associated with serving peak load using an average of the three coincident peak demands ("3CP") occurring in June, July, and August. This method of allocation isolates the costs associated with peaking resources and allocates those costs according to the load that is causing the investment.

The cost allocation method used in the study is based on the concept that the costs associated with each of the Company's generation resources can be categorized according to the type of loads being served. Utilities typically experience three distinct time-based production costing periods that are driven by customer loads. The costing periods are normally identified as base, intermediate, and peak. The base period is equivalent to a low load or off-peak time period where loads are at the lowest, normally during the nighttime hours. The intermediate time period represents the shoulder hours which are driven by the mid-peak loads that typically occur throughout the winter daytime and in the early morning and late evening during the summer months. The peak category is driven by the peak loads that occur during summer afternoons and evenings. The base and intermediate loads on the Company's system are typically served by the same generation resources. In recognition of that fact, those two categories have been combined for cost allocation purposes. The generation resources that serve the peak loads, i.e., combustion turbines, are normally only utilized for that single purpose. Consistent with that concept, the costs associated with peak-related resources have been segmented into a second category for cost allocation purposes. Using this methodology there is no need for marginal cost weighting because the seasonal nature of the loads is reflected in the allocation factors.

The production plant costs that have been classified as serving base and intermediate load are captured in Accounts 310-316, Steam Production, and Accounts 330-336, Hydraulic Production. The costs identified under the Steam Production category represent the Company's investment in coal-fired generation facilities, and the costs identified under the Hydraulic Production category represent the Company's investment in its hydroelectric generation facilities.

Utilities typically utilize their generation resources to serve customer loads by operating the resources with the lowest operating cost first and as demand grows more costly resources are then dispatched. This is no different for Idaho Power. However, since hydroelectric generation is such a significant portion of the Company's resource stack, stream flow conditions and economics can influence the proportionate share of output provided by steam and hydro resources throughout the year. Since hydroelectric output is highly dependent upon stream flows, steam production is ramped up or down according to the production capability of the hydro. Therefore, throughout the year, hydro and steam production plants are utilized at varying proportions to serve base and intermediate loads according to the production capabilities of the hydro plants. However, the combined monthly output of these two resource types does not vary significantly between the summer and non-summer months as does the output of the combustion turbines.

Accounts 340-346, Other Production, contain the Company's investment in gas-fueled production plant. The production plant investment captured in Accounts 340-346 represents the Company's investment in the combustion turbine generation facilities. ***For this study, Bennett Mountain and Danskin power plants are identified as being*** used to serve peak demands, ***and the Company's Langley production resource is considered a baseload resource. The Company, in the Idaho Results of Operations, has provided Accounts 340-346 values for Langley and peaking plants separately to allow for independent allocation of costs.*** The investment identified as peaking plant is the investment in combustion turbine generation resources that were constructed specifically to meet the summer peak loads.

In the Functionalized Cost Module, the names "D10BS" and "D10BNS" 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. The D10BS and

D10BNS represent the non-weighted average twelve coincident peak demands for the summer and non-summer seasons respectively. The allocator D10P represents the non-weighted average three coincident peak demands for the summer months of June, July, and August.

D. Transmission and Distribution Cost Allocation

The Company's approach to cost allocation for transmission and distribution facilities is an effective method for equitably assigning costs to customer classes. Under this method, transmission and distribution costs are properly segmented according to the manner in which the costs are imposed on the system. As a result, the cost responsibility of each class can be effectively identified through a combination of direct cost assignment and cost allocation based on the appropriate demand- or customer-based factors.

The allocation factor D13 is used to allocate transmission costs to customer classes. The first step in deriving this factor is to calculate ratios based on the sum of the actual coincident peak demands for each customer class. Second, weighted coincident peak demand values are derived by multiplying the actual monthly coincident peak demands by the monthly transmission marginal costs. Corresponding weighted ratios are then calculated for each customer class. Finally, the actual ratios are averaged with the weighted ratios to derive the non-seasonalized transmission allocation factor D13. The Company applies this "averaging approach" as a rate stability measure intended to mitigate any extreme impacts that the marginal costs may have on cost allocation.

The capacity components of distribution plant, both primary and secondary, are allocated by the non-coincident group peak demands for each customer class identified as demand allocation factors D20, D30, D50, and D60.

*****The capacity components of distribution plant required to serve Residential and Small General on-site generation customers includes recognition of the bi-directional use of distribution plant to receive and export energy. To evaluate bi-directional capacity requirements, the Residential and Small General on-site generation customers' demand values were evaluated in two manners to correspond to the associated measurement interval, hourly netting, and real-time measurement. For hourly netting, any customer demand value with a negative value at the time of non-coincident group peak was converted to an absolute value. This adjustment recognizes the bi-directional use of the distribution system and creates an allocation factor independent if energy is being consumed or sent to the grid. For real-time measurement, a comparison between the real time delivered and received channels was completed with the maximum value in the hour is used to derive the non-coincident group peak demand.*****

The customer components of distribution plant, both primary and secondary, are allocated by the average number of customers identified as customer allocation factors C20, C30, C50 and C60.

E. Energy-Related Cost Allocation

The energy-related cost allocators, E10S and E10NS, are derived by averaging the normalized energy values for each customer class with the normalized energy values weighted by the marginal energy costs. First, summer and non-summer ratios based on each class's proportionate share of the total normalized energy usage for the test year are determined. Next, summer and non-summer ratios based on the monthly normalized energy usage for each customer class weighted by the monthly marginal cost are calculated. Finally, these two values are averaged, resulting in the E10S and E10NS allocators used in this study. This averaging approach is consistent with the methodology used in the derivation of the demand-related allocation factor D13.

*****Normalized energy values for the Residential and Small General on-site generation customer classes are the energy recorded either under the hourly netting measurement interval, or the real time delivered channel for each respective study. The value for Residential and Small General on-site generation delivered to Idaho Power for both the hourly netting measurement interval, and the real-time measurement interval will be established independently through this docket.*****

F. Customer Accounting and Customer Assistance Expense Allocation

The principal customer accounting expenses which require allocation are meter reading expenses, customer records and collections, and uncollectible accounts. The meter reading and customer records and collection expenses are allocated based upon a review of actual practices of the Company in reading meters and preparing monthly bills. The allocation of uncollectible amounts is similarly based upon a review of actual Company data. Customer assistance expenses are allocated based on the average number of customers in each class.

G. State and Federal Income Tax Allocation

The state and federal income taxes for the Idaho jurisdiction are allocated to each customer class and special contract customer according to each class's allocated share of rate base. Once the state and federal income taxes are allocated to each customer class, they are functionalized based on the functionalization of total rate base and expenses for each class.

VI. REVENUE REQUIREMENT AND APPLICATION

Once all costs have been properly functionalized, classified, and allocated, the Company is able to determine the revenue requirement for each customer class. The sales revenue required includes return on rate base, total operating expenses, and incremental taxes computed using the net-to-gross multiplier.

*****To match the FC Module's Revenues from Rates with the Idaho Results of Operations' exclusion of Valmy levelized revenue, the FC Module includes an adjustment to each class's cost of service results to add back each plant's levelized revenue requirement. Derivation of allocation to each class followed established Assign Module classification and functionalization methodology for each plant. To allocate production baseload demand and energy to each class, established FC Module allocation factors were utilized.*****