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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	)	CASE NO. AVU-E-10-01 CASE NO. AVU-G-10-01 DIRECT TESTIMONY OF TARA L. KNOX

FOR AVISTA CORPORATION

(ELECTRIC AND NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation?

A. My name is Tara L. Knox and my business address is 1411 East Mission Avenue, Spokane, Washington. I am employed as a Senior Regulatory Analyst in the State and Federal Regulation Department.

Q. Would you briefly describe your duties?

A. I am responsible for preparing the regulatory cost of service models for the Company, as well as providing support for the preparation of results of operations reports.

Q. Would you describe your educational background and professional experience?

A. Yes. I am a graduate of Washington State University with a Bachelor of Arts degree in General Humanities in 1982, and a Master of Accounting degree in 1990. As an employee in the State and Federal Regulation Department at Avista since 1991, I have attended several ratemaking classes, including the EEI Electric Rates Advanced Course that specializes in cost allocation and cost of service issues. I have also been a member of the Cost of Service Working Group and the Northwest Pricing and Regulatory Forum, which are discussion groups made up of technical professionals from regional utilities and utilities throughout the United States and Canada concerned with cost of service issues.

Q. What is the scope of your testimony in these proceedings?

A. My testimony and exhibits will cover the Company's electric and natural gas cost of service studies performed for this proceeding. Additionally, I am sponsoring the electric and natural gas revenue normalization adjustments to the test year results of operations and the proposed retail revenue credit rate to be used in the Power Cost Adjustment mechanism. I will also provide an overview of the electric load research study that was recently completed by the Company. A table of contents for my testimony is as follows:

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Q. Are you sponsoring any Exhibits with your pre-filed testimony?

A. Yes. I am sponsoring Exhibit No. 13 composed of six schedules as follows: Schedule 1, retail revenue credit rate calculation; Schedule 2, electric cost of service study process description; Schedule 3, electric cost of service study summary results; Schedule 4, load research study report; Schedule 5, natural gas cost of service study process description; and Schedule 6, natural gas cost of service summary results.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

II. REVENUE NORMALIZATION

Electric Revenue Normalization

Q. Would you please describe the electric revenue adjustment included in Company witness Ms. Andrews pro forma results of operations?

A. Yes. The electric revenue normalization adjustment represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2009 test period and retail revenues on a normalized (pro forma) basis. The total revenue normalization adjustment increases Idaho net operating income by $3,620,000, as shown in column (z) on page 6 of Ms. Andrews Exhibit No.12, Schedule 1. The revenue normalization adjustment consists of three primary components: 1) re-pricing customer usage (adjusted for any known and measurable changes) at present base tariff rates in effect, 2) adjusting customer loads and revenue to a 12-month calendar basis (unbilled revenue adjustment), and 3) weather normalizing customer usage and revenue[1].

Q. Since these three elements are combined into a single adjustment, would you please identify the impact (before taxes and revenue related expenses) of each component?

A. Yes. The re-pricing of billed usage comprises the majority of the change in test year revenue. The combined impact of the rate increase effective August 1, 2009 and the elimination of revenue and amortization expense from adder schedules (Schedule 59 Residential Exchange, and Schedule 91 Public Purpose Tariff Rider[2]) is an increase of $9,302,000. Revenue from unbilled calendar usage compared to the amount included in results of operations is a reduction of $134,000[3]. Finally, the weather normalization adjustment reduces revenue by $3,497,000. The combined impact of these elements is an increase of $5,671,000 which, after revenue-related expenses and income taxes, results in the increase to net operating income of $3,620,000.

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[1] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.
[2] City Franchise Fee and Power Cost Adjustment revenues are eliminated in separate adjustments.
[3] The unbilled adjustment consists of removing December 2008 usage billed in January 2009 from the 2009 test year, adding December 2009 usage billed in January 2010 to the 2009 test year, and re-pricing the net adjustment to usage at the base rates presently in effect.

Q. Would you please briefly discuss electric weather normalization?

A. Yes. The Company's weather normalization adjustment calculates the change in kWh usage required to adjust actual loads during the twelve months ended December 2009 test period to the amount expected if weather had been normal. This adjustment incorporates the effect of both heating and cooling on weather-sensitive customer groups. The weather adjustment is developed from regression analysis of five years of billed usage per customer and billing period heating and cooling degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating degree-day and use-per-customer-per-cooling degree-day) are applied to monthly test period customers and the difference between normal heating/cooling degree-days and monthly test period observed heating/cooling degree-days.

Q. Have the seasonal weather sensitivity factors been updated since the last rate case?

A. No. Regression analysis was performed on 2004 through 2008 billing data which resulted in higher sensitivity factors. Use of these higher sensitivity factors would have resulted in a greater reduction in usage which in turn would have increased the current rate request. In an effort to present a conservative estimate of the impact of abnormal weather during 2009 (beneficial to customers), the Company elected to stay with the previous factors.

Q. What data did you use to determine "normal" heating and cooling degree days?

A. Normal heating and cooling degree-days are based on a rolling 30-year average of heating and cooling degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest year dropping off, thereby reflecting the most recent information available at the end of each calendar year.

Q. Is this proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Idaho?

A. Yes.

Q. What was the impact of electric weather normalization on the twelve months ended December 2009 test year?

A. Weather was colder than normal during the winter and spring, and warmer than normal during the summer of 2009. The adjustment to normal required the deduction of 430 heating degree-days during the heating season[4] and 155

[4] The heating season includes the months of January through June and October through December.

cooling degree-days. The total adjustment to Idaho sales volumes was a reduction of 44,832,283 kWhs which is approximately 1.3 percent of billed usage.

Natural Gas Revenue Normalization

Q. Would you please describe the natural gas revenue adjustment included in Ms. Andrews pro forma results of operations?

A. Yes. The natural gas revenue normalization adjustment is similar to the electric adjustment and represents the difference between the Company's actual recorded retail revenues during the twelve months ended December 2009 test period and retail revenues on a normalized (pro forma) basis. The adjustment includes the re-pricing of pro forma sales and transportation volumes at present rates (effective November 1, 2009) using pro forma sales volumes that have been adjusted for unbilled sales, abnormal weather, and any material customer load or schedule changes. The rates used exclude: 1) Temporary Gas Rate Adjustment Schedule 155, which reflects the approved amortization rate for deferred gas costs approved in the Company's last PGA filing and 2) Public Purposes Rider Adjustment Schedule 191[5].

Q. Does the Revenue Normalization Adjustment contain a component reflecting normalized gas costs?

[5] Documentation related to this adjustment is detailed in the Knox workpapers accompanying this case.

A. Yes. Purchase gas costs are normalized using the gas costs approved by the Commission in Case No. AVU-G-09-05, the Company's 2009 PGA filing, as set forth under Schedule 150. Those gas costs are then applied to the pro forma retail sales volumes so that there is a matching of revenues and gas costs.

The total net amount of the natural gas revenue normalization, which includes the purchase gas cost adjustment, is a decrease to net operating income of $537,000, as shown in column (h), page 6 of Ms. Andrews Exhibit No.12, Schedule 2.

Q. Would you please briefly discuss natural gas weather normalization?

A. Yes. The natural gas weather adjustment is developed from a regression analysis of ten years of billed usage-per-customer and billing period heating degree-day data. The resulting seasonal weather sensitivity factors (use-per-customer-per-heating degree-day) are applied to monthly test period customers and the difference between normal heating degree-days and monthly test period observed heating degree-days. This calculation produces the change in therm usage required to adjust existing loads to the amount expected if weather had been normal.

Q. In your discussion of electric weather normalization you indicated that the adjustment utilized

sensitivity factors from the last case. Is this true for natural gas as well?

A. Yes. Once again, in an effort to present a more conservative reduction to usage due to abnormal weather, the factors from the last case were used instead of updated factors which indicated slightly higher sensitivity.

Q. What data did you use to determine "normal" heating degree days?

A. Normal heating degree-days are based on a rolling 30-year average of heating degree-days reported for each month by the National Weather Service for the Spokane Airport weather station. Each year the normal values are adjusted to capture the most recent year with the oldest data dropping off, thereby reflecting the most recent information available at the end of each calendar year.

Q. Is the proposed weather adjustment methodology consistent with the methodology utilized in the Company's last general rate case in Idaho?

A. Yes. The process for determining the weather sensitivity factors and the monthly adjustment calculation are consistent with the methodology presented in Case No. AVU-G-09-01.

Q. What was the impact of natural gas weather normalization on the twelve months ended December 2009 test year?

A. Weather was colder than normal during the 2009 winter and spring months. The adjustment to normal required the deduction of 430 heating degree-days from January through June and October through December.[6] The adjustment to sales volumes was a reduction of 3,762,074 therms which is approximately three percent of billed usage. The margin impact (revenue less gas cost) of the weather adjustment was a reduction of $1,187,000.

III. PROPOSED ELECTRIC RETAIL REVENUE CREDIT RATE

Q. Company witness Mr. Johnson indicates that the retail revenue credit rate to be used in the Power Cost Adjustment (PCA) represents the average cost of production and transmission in this filing. How is that rate determined?

A. The retail revenue credit rate is determined by computing the proposed revenue requirement on the production and transmission costs contained within Ms. Andrews' Idaho electric pro forma total results of operations. The production/transmission revenue requirement amount is then divided by the Idaho normalized retail load used to set rates in order to arrive at the average production and transmission cost-per-kWh embedded in proposed rates.

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[6] Warmer than normal weather that occurred during July through September did not impact the natural gas weather normalization adjustment as the seasonal sensitivity factor is zero for summer months.

Q. Do you have an exhibit that shows the calculation of the proposed retail revenue credit rate?

A. Yes. Exhibit No. 13, Schedule 1 begins with the identification of the production and transmission revenue, expense and rate base amounts included in each of Ms. Andrews actual, restating, and pro forma adjustments to results of operations. The "Pro Forma Total" at the bottom of page 1 shows the resulting production and transmission cost components.

Page 2 shows the revenue requirement calculation on the production and transmission cost components. The rate of return and debt cost percentages on line 2 are inputs from the proposed cost of capital. The normalized retail load on Line 10 comes from the workpapers to the revenue normalization adjustment. The proposed retail revenue credit rate is shown on Line 11 and represents the average production and transmission cost-per-kWh proposed to be embedded in Idaho customer retail rates.

The proposed retail revenue credit rate is $0.05026 per kWh or $50.26 per mWh. The calculation of the retail revenue credit rate will be revised based on the final production and transmission costs and rate of return that are approved by the Commission in this case.

IV. ELECTRIC COST OF SERVICE

Q. Please briefly summarize your testimony related to the electric cost of service study.

A. I believe the Base Case cost of service study presented in this case is a fair representation of the costs to serve each customer group. The Base Case study shows Residential Service Schedule 1, Extra Large General Service Schedule 25 and 25P, and Pumping Service Schedule 31 provide less than the overall rate of return under present rates. General Service Schedule 11, Large General Service Schedule 21 and Street and Area Lighting Service provide more than the overall rate of return under present rates.

Q. What is an electric cost of service study and what is its purpose?

A. An electric cost of service study is an engineering-economic study, which separates the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. The groups are made up of customers with similar load characteristics and facilities requirements. Costs are assigned in relation to each group's characteristics, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers. Exhibit No. 13, Schedule 2 explains the basic concepts involved in performing an electric cost of service study. It also details the specific methodology and assumptions utilized in the Company's Base Case cost of service study.

Q. What is the basis for the electric cost of service study provided in this case?

A. The electric cost of service study provided by the Company as Exhibit No.13, Schedule 3 is based on the twelve months ended December 2009 test year pro forma results of operations presented by Company witness Ms. Andrews in Exhibit No.12, Schedule 1.

Q. Would you please explain the cost of service study presented in Exhibit No. 13, Schedule 3?

A. Yes. Exhibit No. 13, Schedule 3 is composed of a series of summaries of the cost of service study results. The summary on page 1 shows the results of the study by FERC account category. The rate of return by rate schedule and the ratio of each schedule's return to the overall return are shown on Lines 39 and 40. This summary was provided to Mr. Ehrbar for his work on rate spread and rate design. The results will be discussed in more detail later in my testimony.

Pages 2 and 3 are both summaries that show the revenue-to-cost relationship at current and proposed revenue. Costs by category are shown first at the existing schedule returns (revenue); next the costs are shown as if all schedules were providing equal recovery (cost). These comparisons show how far current and proposed rates are from rates that would be in alignment with the cost study. Page 2 shows the costs segregated into production, transmission, distribution, and common functional categories. Page 3 segregates the costs into demand, energy, and customer classifications. Page 4 is a summary identifying specific customer related costs embedded in the study.

The Excel model used to calculate the cost of service and supporting schedules has been included in its entirety both electronically and hard copy in the workpapers accompanying this case.

Q. Does the Company's electric Base Case cost of service study follow the methodology accepted in the Company's last electric general rate case in Idaho?

A. Only in part. The methodology applied to distribution and administrative and general costs has not changed from the methodology accepted by the Idaho Commission in Case No. AVU-E-04-01 and subsequently presented in AVU-E-08-01 and AVU-E-09-01. However, the

Company is proposing a revision to the peak credit classification for production costs and a change to the methodology applied to transmission costs in this case.

Q. With respect to the components that have not changed (given that the specific details of this methodology are described in Exhibit No. 13, Schedule 2), would you please give a brief overview of the key elements and the history associated with those elements?

A. Yes. Distribution costs are classified and allocated by the basic customer theory[7] accepted by the Idaho commission in Case No. WWP-E-98-11. Additional direct assignment of demand related distribution plant has been incorporated to reflect improvements accepted by the Commission in Case No. AVU-E-04-01.

Administrative and general costs are first directly assigned to production, transmission, distribution, or customer relations functions. The remaining administrative and general costs are categorized as common costs and have been assigned to customer classes by the four-factor allocator accepted by the Idaho Commission in Case No. AVU-E-04-01.

Q. Moving on to components of the study that have changed, let's start with production costs. You said the

[7] Basic customer theory classifies only meters, services and the direct assignment of street light fixtures as customer-related plant; all other distribution facilities are considered demand-related.

Company is proposing a revision to the peak credit classification for production cost. Please explain.

A. In addition to preparing a new load study, the Company also decided to examine the operating characteristics, and associated costs, of its electric system resources in conjunction with the allocation of costs within its cost of service study. Traditionally, both production and transmission costs have been classified into energy-related and demand-related components by the peak credit ratio method. Therefore the "peak credit" classification methodology was evaluated to determine whether it was appropriate to make any changes, given our current electric system characteristics.

Q. How was the prior peak credit methodology determined and applied?

A. In the Company's prior cost of service studies, Avista's electric system resource costs were classified to energy and demand using a comparison of the replacement cost-per-kW of the Company's peaking units, to the replacement cost-per-kW of the Company's thermal and hydro plants (separately). This analysis created separate peak credit ratios applied to thermal plant and hydro plant. Transmission costs were assigned to energy and demand by a 50/50 weighting of the thermal and hydro peak credit ratios. Fuel and load dispatching expenses were classified entirely to energy, and peaking plant related costs were classified entirely to demand.

Q. What is the Company proposing with regard to the peak credit methodology and how was it developed?

A. Energy Resources Department personnel were enlisted to examine the issue. The result of their analysis is reflected in Company witness Mr. Kalich's recommended revised peak credit classification ratio of 38.1% applied uniformly to all production costs. As explained by Mr. Kalich, the peak credit ratio (the proportion of total production cost that is capacity-related) is determined using the operational model of the incremental capacity resource detailed in the Company's latest Integrated Resource Plan. The ratio of the costs remaining after dispatch into the wholesale marketplace relative to the entire cost of the incremental resource is the share of production costs attributable to demand.

Q. What is the net effect of the proposed change in the peak credit method?

A. The net effect of this change is to increase the overall production costs that are classified as demand-related. Using the prior method, approximately 26% of total production costs were classified as demand-related, compared to 38.1% under the revised method. This change shifts costs away from high load factor customer groups as well as customer groups which have a limited contribution to system peak usage (pumping and street lighting).

Q. Moving on to transmission, you mentioned the Company is proposing "a change to the methodology applied to transmission costs". What are you changing and why?

A. The proposed method applied in the Base Case cost of service study incorporates changes to both the classification and allocation of transmission costs. These changes resulted from examining the issues raised by the intervening parties in Case No. AVU-E-09-01. In fact, as part of the Settlement Agreement in Case No. AVU-E-09-01, the Company agreed to the following:

> As part of its next general rate case (GRC), the Company will prepare an analysis of the impacts of allocating 100% of transmission costs to demand, as well as allocating transmission costs to reflect any peak and off-peak seasonal cost differences over seven months, rather than assuming an equal weighting over twelve months. (page 11).

Q. How did you change the classification of transmission costs?

A. Historically, Avista has included transmission costs in the production peak credit classification. It has been done this way largely because it is the accepted process in Washington, even though, as the interveners pointed out, 100% demand is the more universally accepted classification of transmission costs in other states (including the other investor-owned utilities in Idaho).

In the Base Case cost of service study in this case, all transmission costs have been classified as demand-related.

Q. Did you make any further changes to the allocation of transmission costs?

A. Yes. In prior studies, demand-related transmission costs have been allocated to customer groups by their contributions to the average of the twelve monthly system coincident peaks. In this study, only the system coincident peaks occurring in 4 winter months and 3 summer months were included in the average. The rationale behind this allocation is that the lower customer demands in the off-peak fall and spring seasons do not impose the same capacity utilization of the transmission facilities as the high demand winter and summer seasons.

Q. The Settlement Agreement only required the Company to prepare an analysis of the impact of these two issues. Why did you include them in the Base Case cost of service study?

A. There are reasonable arguments supporting both of these changes, some of which are identified above. In addition, these changes reduce cost allocation to high load factor customers. Since the last test year, we have seen the number of Schedule 25 Extra Large General Service customers reduced by one-third, as the forest industry in particular continues to experience financial difficulties.

Choosing acceptable methodologies that can legitimately reduce cost pressure for this group of customers represents a conscious effort to help keep this segment in business.

Q. What are the results of the Company's Base Case cost of service study?

A. The following table shows the rate of return and the relationship of the customer class return to the overall return (relative return ratio) at <u>present</u> <u>rates</u> for each rate schedule:

Illustration 1:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 1	4.06%	0.78
General Service Schedule 11	8.68%	1.67
Large General Service Schedule 21	6.47%	1.25
Extra Large General Service Schedule 25	2.72%	0.53
Ex. Lg. Gen. Svc. Clearwater Paper Schedule 25P	4.47%	0.86
Pumping Service Schedule 31	4.55%	0.88
Lighting Service Schedules 41 - 49	6.30%	1.21
Total Idaho Electric System	5.19%	1.00

As can be observed from the above table, residential, extra large general service, and pumping service schedules (1, 25, 25P, and 31) show under-recovery of the costs to serve them, while the general, large general, and lighting service schedules (11, 21, and 41 - 49) show over-recovery of the costs to serve them. The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. Can you illustrate how the changes to the methodology applied to production and transmission costs impacted the cost of service study results?

A. Yes. The following table contains the progression in the relative return ratio from the model run of the study using the prior method to the proposed Base Case method.

Illustration 2:

Customer Class	Prior Method	Step 1 Revised Peak Credit	Step 2 Revised Peak Credit and Transmission 100% Demand	Base Case Revised Peak Credit Transmission 100% Demand & 7CP
Schedule 1	0.87	0.83	0.80	0.78
Schedule 11	1.72	1.70	1.67	1.67
Schedule 21	1.25	1.24	1.24	1.25
Schedule 25	0.46	0.49	0.51	0.53
Schedule 25P	0.59	0.74	0.83	0.86
Schedule 31	0.79	0.83	0.85	0.88
Schedules 41-49	1.12	1.17	1.21	1.21
Total Idaho	1.00	1.00	1.00	1.00

This illustration shows the impact of each incremental change to the electric cost of service methodology.

Demand Study

Q. An issue was raised in Case No. AVU-E-08-01 regarding the load data used to develop demand allocations

in the electric cost of service. Please elaborate on this issue.

A. In the Company's 2008 general rate case, the Company indicated that, while the estimation process used to create the demand allocators in the cost of service study provides a reasonable assignment of cost to the existing customer groups, the Company's load data was in the process of being updated. Accordingly, the Commission provided the following directive on page 13 of its Order No. 30647:

> In this case the Commission finds the Company-filed cost of service study to be sufficient to determine rate design in this case. We direct the Company in its next general rate case to provide updated load data as part of its COS study or, in the alternative, show how the lack of such an update affects COS-based revenue allocations to customer classes.

Q. How was this issue treated in the Company's 2009 general rate case?

A. The load study was in progress during the pendency of Case No. AVU-E-09-01. Even though the Company presented sensitivity analysis to illustrate the potential impact of updated load information on cost of service based revenue allocations, the parties ultimately agreed to spread the increase in electric base revenue on a uniform percentage basis. The Company also agreed as part of the approved settlement to share the results of the load study as soon as it became available. This contingency was meant to assure the parties that if another case had been filed before the load study had been completed, the results could be considered during the case as soon as they did become available.

Q. Has Avista incorporated current load research into the cost-of-service study presented for this case?

A. Yes. The Company designed and implemented a load research study in 2009. The results of that study were applied within the Company's cost-of-service study.

Q. How does the load research influence the cost-of-service study?

A. Many of the components of a cost-of-service study are distributed among the various rate classes based upon the energy use and demand of that customer class during different time periods. A load research study is a measurement of a statistically valid sample of each customer class used to estimate how that customer class contributes to the overall system load. Those contributions then become part of the cost-of-service study.

Q. How was this load study performed?

A. In 2008, Avista reviewed the tasks necessary for the design and implementation of a long-term load research study that would deliver usable results based upon one full year of data. The goal was to have this study ready for regulatory proceedings no later than the Spring of 2010. The requirement of randomly selecting customers for participation in the study and the diverse and often low-density nature of much of our service territory demanded a high-quality and reliable metering and communication system to support a long-term study. The Company retained a load research consulting specialist to design the sample to deliver statistically valid results.

Avista interviewed four consulting firms. Based on these interviews and other due diligence, the Company engaged the services of Mr. Curt Puckett of KEMA (formerly known as RLW Analytics) to provide planning, sample design and selection, as well as analysis and reporting associated with Avista's Load Research Project. KEMA is a respected consulting firm specializing in electric utility load research.

Q. How many customers were selected for the project?

A. In total, 629 Avista customers were included in the overall sample. This included 225 customers within the Company's Idaho service territory. The remaining 404 customers were in the Company's Washington service territory.

Q. How were external stakeholders involved in this process?

A. The Company's load research team (consisting of Jon Powell, Jon Seubert, and myself) as well as Mr. Puckett of KEMA met with Commission Staff May 21, 2008 in Boise. The Company presented the initial plan for the study and requested input from the parties before finalizing the plan and commencing implementation of the project. A project update was also sent on October 31, 2008 to mark the installation of the first of the sample meters. Finally, periodic updates were presented to the Company's External Energy Efficiency Board (Triple-E).

Since that time, Avista has been collecting the data from the meters and forwarding the resulting meter reads to KEMA for their analysis. On March 16, 2010, KEMA delivered to Avista the final load research study[8]. The load research study report is attached as Exhibit No. 13, Schedule 5 and the supporting electronic files have been included in the accompanying workpapers.

Q. Were the stakeholders made aware of the key elements of the load research study?

A. Yes. Stakeholders were informed of the issues involved in choice of technology, sample selection and the timetable for the completion of the installation and evaluation.

[8] Key result tables were provided in late February to facilitate incorporation of the load study results in the presented cost of service analysis, however the complete load study report was not delivered until March.

Q. Did the results from the new load study cause major changes in the allocation of demand-related costs in the cost of service study in this case, as compared to prior cost of service studies?

A. No. Using the prior case method cost of service run (for an apples to apples comparison), the demand contributions produced by the load study increased the relative costs assigned to pumping service and reduced the costs assigned to lighting service. Otherwise, the over- and under-recovery relationships are similar to studies from prior cases.

Q. Is the cost-of-service study the only anticipated use of the load research study?

A. No. We have found additional use of the load research in improving transformer design and potentially in the design and implementation of Smart Grid technologies. We are also contemplating the future use of this data to develop end-use load profiles.

Q. How will Avista maintain the study in the future?

A. It is Avista's intent to annually augment the existing customer sample with additional, randomly-selected participants, beginning in 2011. These additional installations will ensure that the study sample continues to be representative of the population as a whole. The additional samples will be selected to maximize statistical precision of the rate classes and to serve the needs of evaluating future alternative rate designs and engineering topics that arise over time.

V. NATURAL GAS COST OF SERVICE

Q. Please describe the natural gas cost of service study and its purpose.

A. A natural gas cost of service study is an engineering-economic study which separates the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. The groups are made up of customers with similar usage characteristics and facility requirements. Costs are assigned in relation to each groups' characteristics, resulting in an evaluation of the cost of the service provided to each group. The rate of return by customer group indicates whether the revenue provided by the customers in each group recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers. Exhibit No.13, Schedule 5 explains the basic concepts involved in performing a natural gas cost of service study. It also details the specific methodology and assumptions utilized in the Company's Base Case cost of service study.

Q. What is the basis for the natural gas cost of service study provided in this case?

A. The cost of service study provided by the Company as Exhibit No.13, Schedule 6 is based on the twelve months ended December 2009 test year pro forma results of operations presented by Ms. Andrews in Exhibit No.12, Schedule 2.

Q. Would you please explain the cost of service study presented in Exhibit No. 13, Schedule 6?

A. Yes. Exhibit No. 13, Schedule 6 is composed of a series of summaries of the cost of service study results. Page 1 shows the results of the study by FERC account category. The rate of return and the ratio of each schedule's return to the overall return are shown on lines 38 and 39. This summary is provided to Mr. Ehrbar for his work on rate spread and rate design. The results will be discussed in more detail later in my testimony. Additional summaries show the costs organized by functional category (page 2) and classification (page 3), including margin and unit cost analysis at current and proposed rates. Finally, page 4 is a summary identifying specific customer related costs embedded in the study.

The Excel model used to calculate the cost of service and supporting schedules has been included in its entirety both electronically and hard copy in the workpapers accompanying this case.

Q. Does the Natural Gas Base Case cost of service study utilize the methodology from the Company's last natural gas case in Idaho?

A. Yes. The Base Case cost of service study was prepared using the methodology accepted by the Idaho Commission in Case No. AVU-G-04-01, AVU-G-08-01 and AVU-G-09-01.

Q. What are the key elements that define the cost of service methodology?

A. Purchased gas costs are derived from the current purchased gas tracker methodology. Underground storage costs are allocated by normalized winter throughput. Natural gas main investment has been segregated into large and small mains. Large usage customers that take service from large mains do not receive an allocation of small mains. Meter installation and services investment is allocated by number of customers weighted by the relative current cost of those items. System facilities that serve all customers are classified by the peak and average ratio that reflects the system load factor, then allocated by coincident peak demand and throughput, respectively. Demand side management costs are treated in the same way as system facilities. General plant is allocated by the sum of all other plant. Administrative & general expenses are segregated into labor-related, plant-related, revenue-related, and "other". The costs are then allocated by factors associated with labor, plant in service, or revenue, respectively. The "other" A&G amounts get a combined allocation that is one-half based on O&M expenses and one-half based on throughput. A detailed description of the methodology is included in Exhibit No.13, Schedule 5.

Q. What are the results of the Company's natural gas cost of service study?

A. I believe the Base Case cost of service study presented in this filing is a fair representation of the costs to serve each customer group. The study indicates that Residential service Schedule 101 is providing slightly less than the overall return (unity), while all other schedules are providing slightly more than unity to varying degrees. The return for all of the Schedules are relatively close to the overall return indicating the current rate spread is fair.

The following table shows the rate of return and the relative return ratio at <u>present</u> <u>rates</u> for each rate schedule:

Illustration 3:

Customer Class	Rate of Return	Return Ratio
Residential Service Schedule 101	6.57%	0.95
Large Firm Service Schedule 111	8.65%	1.25
Interruptible Service Schedule 131	7.51%	1.08
Transportation Service Schedule 146	8.83%	1.27
Total Idaho Natural Gas System	6.93%	1.00

The summary results of this study were provided to Mr. Ehrbar as an input into development of the proposed rates.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION	)	CASE NO. AVU-E-10-01
OF AVISTA CORPORATION FOR THE	)	CASE NO. AVU-G-10-01
AUTHORITY TO INCREASE ITS RATES	)	
AND CHARGES FOR ELECTRIC AND	)	
NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 13
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	TARA L. KNOX
	)	

FOR AVISTA CORPORATION

(ELECTRIC AND GAS)

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2009

Column	Description of Adjustment	(000's)	Revenue	Production/Transmission Expense	Rate Base
b	Per Results Report		84,836	205,345	359,043
c	Deferred FIT Rate Base			-	(51,323)
d	Deferred Gain on Office Building			-	
e	Colstrip 3 AFUDC Elimination		-	193	1,700
f	Colstrip Common AFUDC		-	-	903
g	Kettle Falls & Boulder Park Disallow.		-	-	(2,034)
h	Customer Advances			-	
i	Weatherizn and DSM Investment		-	-	294
j	Restating CDA Settlement		-	307	(17)
k	Restating CDA Settlement Deferral		-	101	168
l	Restating CDA/SRR CDR		-	756	400
m	Restating Spokane Rvr Relicensing		-	118	(459)
n	Restating Spokane River Deferral		-	19	32
o	Restating Spokane River PM&E Deferral		-	156	253
p	Restating Montana Lease		-	44	1,289
	Actual		84,836	207,039	310,249
q	Eliminate B & O Taxes			-	
r	Property Tax			776	
s	Uncollect. Expense			-	
t	Regulatory Expense			-	
u	Injuries and Damages			-	
v	FIT			-	
w	Idaho PCA			465	
x	Nez Perce Settlement Adjustment			(15)	
y	Eliminate A/R Expenses			-	
z	Revenue Normalization Adjustment		59	2,400	
aa	Misc Restating Adjs			-	
ab	Colstrip Mercury Emiss. O&M			481	
ac	Restating CS2 Levelized Adj			221	
ad	Restating Wartsila Amortization			108	
ae	Restating Colstrip Lawsuit Stlmnt			154	
af	Restating CCX			425	
ag	O&M Savings			(83)	
ah	Working Capital			-	
ai	Restate Debt Interest			-	
	Restated Total		84,895	211,971	310,249
PF1	Pro Forma Power Supply		(61,099)	(50,780)	-
PF2	Pro Forma Production Property Adj		(774)	(4,505)	(4,853)
PF3	Pro Forma Labor Non-Exec			324	
PF4	Pro Forma Labor Exec			1	
PF5	Pro Forma Transmission Rev/Exp		1,036	94	-
PF6	Pro Forma Capital Add 2009			130	7,824
PF7	Pro Forma Capital Add 2010			558	677
PF8	Pro Forma Noxon Gen 2010 & 2011			201	4,362
PF9	Pro Forma Information Services			2	
PF10	Pro Forma Employee Benefits			(204)	
PF11	Pro Forma Insurance			-	
PF12	Pro Forma Clark Fork/Spokane Rel PM&E			1,089	-
	Pro Forma Total		24,058	158,881	318,259

AVISTA UTILITIES

AVERAGE PRODUCTION AND TRANSMISSION COST
IDAHO ELECTRIC
TWELVE MONTHS ENDED DECEMBER 31, 2009

Proposed Production and Transmission Revenue Requirement
Calculation of Retail Revenue Credit Rate at Proposed Return

Line			($000's)	Debt Cost
1	Prod/Trans	Pro Forma Rate Base	$318,259	
2		Proposed Rate of Return	8.550%	3.100%
3	Rate Base	Net Operating Income Requirement	$27,211	
4	Tax Effect	Net Operating Income Requirement (Rate Base x Debt Cost x -35%)	($3,453)	
5	Net Expense	Net Operating Income Requirement (Expense - Revenue)	134,823	
6	Tax Effect	Net Operating Income Requirement (Net Expense x -.35%)	($47,188)	
7	Total Prod/Trans	Net Operating Income Requirement	$111,393	
8	1 - Tax Rate	Conversion Factor (Excl. Rev. Rel. Exp.)	0.65	
9	Prod/Trans	Revenue Requirement	$171,374	
10	ID Test Year Normalized Retail Load MWh		3,409,476	
11	Prod/Trans Rev Requirement per kWh (Retail Revenue Credit Rate)		$ 0.05026	

1. ELECTRIC COST OF SERVICE

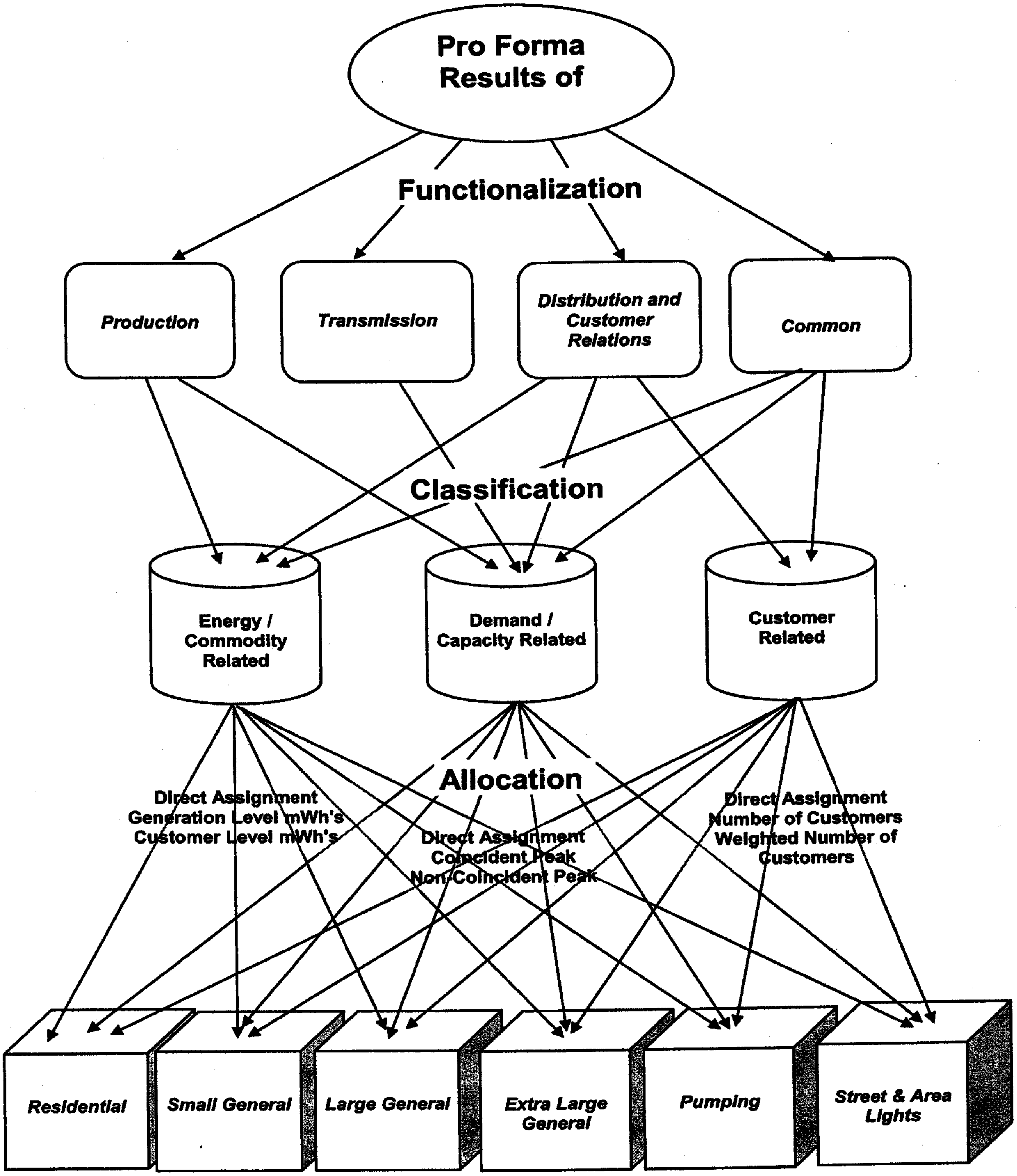
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing electric service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart below.

First, the expenses and rate base associated with the electric system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, transmission, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items that cannot be directly assigned to customer groups are classified into three primary cost components: energy, demand or customer related. Energy related costs are allocated based on each rate schedule's share of commodity consumption. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to peak demand. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

ELECTRIC COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

Exhibit No. 13
Case No. AVU-E-10-01
T. Knox, Avista
Schedule 2, p. 2 of 9

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production Classification (Peak Credit)

This study utilizes a Peak Credit methodology to classify production costs into demand and energy classifications. The Peak Credit method acknowledges that all energy production costs contain both capacity and energy components as they provide energy throughout the year as well as capacity during system peaks. The peak credit ratio (the proportion of total production cost that is capacity related) is determined using the operational model of the incremental capacity resource detailed in the Company's latest Integrated Resource Plan. The ratio of the costs remaining after dispatch into the wholesale marketplace relative to the entire cost of the incremental resource is the share of production costs attributable to demand.

Production Allocation

Production demand related costs are allocated to the customer classes by class contribution to the average of the twelve monthly system coincident peak loads. Although the Company is usually technically a winter peaking utility, it experiences high summer peaks and careful management of capacity requirements is required throughout the year. The use of the average of twelve monthly peaks recognizes that customer capacity needs are not limited to the heating season. Energy related costs are allocated to class by pro forma annual kilowatthour sales adjusted for losses to reflect generation level consumption.

Transmission Classification and Allocation

Transmission costs are classified as 100% demand related because the facilities are constructed primarily for meeting system peak loads. These costs are then allocated to the customer classes by class contribution to the average of the four monthly system coincident peak loads during the winter and the three monthly system coincident peak loads during the summer. Lower customer demands in the off-peak fall and spring seasons do not impose the same capacity utilization of the transmission facilities as the high demand winter and summer seasons.

Distribution Facilities Classification (Basic Customer)

The Basic Customer method considers only services and meters and directly assigned Street Lighting apparatus (FERC Accounts 369, 370, and 373 respectively) to be customer related distribution plant. All other distribution plant is then considered demand related. This division delineates plant which benefits an individual customer from plant which is part of the system. The basic customer method provides a reasonable, clearly definable division between plant that provides service only to individual customers from plant that is part of the interconnected distribution network.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part they are classified as customer related. Exceptions are sales expenses which are classified as energy related and uncollectible accounts expense which is considered separately as a revenue conversion item. Demand Side Management expenses recorded in Account 908 are also considered separately from the other customer information costs.

The demand side management investment and amortization are classified implicitly to demand and energy by the sum of production plant in service, then allocated to rate schedules by coincident peak demand and energy consumption respectively.

Distribution Cost Allocation

Distribution demand related costs which cannot be directly assigned are allocated to customer class by the average of the twelve monthly non-coincident peaks for each class. Distribution facilities that serve only secondary voltage customers are allocated by the non-coincident peak excluding primary voltage customers or number of customers excluding primary voltage customers. This includes line transformers, services, and secondary voltage overhead or underground conductors and devices. The costs of specific substations and related primary voltage distribution facilities are directly assigned to Extra Large General Service customers based on their load ratio share of the substation capacity from which they receive service.

Most customer costs are allocated by average number of customers. Weighted customer allocators have been developed using typical current cost of meters, estimated meter reading time, and direct assignment of billing costs for hand-billed customers. Street and area light customers are excluded from metering and meter reading expenses as their service is not metered.

Administrative and General Costs

Administrative and general costs which are directly associated with production, transmission, distribution, or customer relations functions are directly assigned to those functions and allocated to customer class by the relevant plant or number of customers. The remainder of administrative and general costs are considered common costs, and have been left in their own functional category. These common costs are classified by the implicit relationship of energy, demand and customer within the four-factor allocator applied to them. The four-factor allocator consists of a 25% weighting of each of the following: 1) operating & maintenance expenses excluding resource costs, labor expenses, and administrative and general expenses; 2) operating and maintenance labor expenses excluding administrative and general labor expenses; 3) net production, transmission, and distribution plant; and 4) number of customers.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax adjusted by interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category by that ratio. Similarly, income tax items have been reduced to a percent of net income before tax then assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case cost of service study.

IPUC Case No. AVU-E-10-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Production Plant			
1	Thermal Production	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
2	Hydro Production	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
3	Other Production (Coyote Springs)	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
4	Other Production	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Transmission Plan			
5	All Transmission	T = Transmission	Demand	D02 7 Month Average Coincident Peak Demand (4 Winter and 3 Summer Month Peaks)
	Distribution Plan			
6	360 Land	D = Distribution	Demand	D03 Non-coincident Peak Demand (NCP)
7	361 Structures	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
8	362 Station Equipment	D = Distribution	Demand	D04/D05/D06 Direct Assign Large / Non-coincident Peak Demand Excl DA
9	364 Poles Towers & Fixtures	D = Distribution	Demand	D04/D05/D07/D08 Direct Assign Large & Lights / NCP Excl DA / NCP Secondary
10	365 Overhead Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
11	366 Underground Conduit	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
12	367 Underground Conductors & Devices	D = Distribution	Demand	D04/D05/D07 Direct Assign Large / NCP Excl DA / NCP Secondary
13	368 Line Transformers	D = Distribution	Demand	D07 Non-coincident Peak Demand Secondary
14	369 Services	D = Distribution	Customer	C02 Secondary Customers unweighted Excl Lighting
15	370 Meters	D = Distribution	Customer	C04 Customers weighted by Current Typical Meter Cost
16	373 Street and Area Lighting Systems	D = Distribution	Customer	C05 Direct Assignment to Street and Area Lights
	General Plant			
17	All General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Intangible Plant			
18	301 Organization	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
19	302 Franchises & Consents - Hydro Relicensing	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
20	303 Misc Intangible Plant - Transmission Agreements	T = Transmission	Demand	D02 7 Month Average Coincident Peak Demand (4 Winter and 3 Summer Month Peaks)
21	303 Misc Intangible Plant - Software	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Reserve for Depreciation/Amortizatio			
22	Intangible	P/T/O	Follows Related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Allocator
23	Production	P = Production	Follows Related Plant	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
24	Transmission	T = Transmission	Follows Related Plant	D02 7 Month Average Coincident Peak Demand (4 Winter and 3 Summer Month Peaks)
25	Distribution	D = Distribution	Follows Related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
26	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Other Rate Base			
27	252 Customer Advances for Construction	D = Distribution	Customer	S13 Sum of Account 369 Services Plant
28	282/190 Accumulated Deferred Income Tax	P/T/D/O by Plant Balances	Follows Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
29	Gain on Sale of General Office Building	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
30	Hydro Relicensing Related Settlements	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
31	Demand Side Management Investment	DSM	Demand/Energy from Production Plant	S01 Sum of Production Plant
32	Working Capital	P/T/D/G	Demand/Energy/Customer as in related Plant	S06 Sum of Production, Transmission, Distribution, and General Plant
	Production O&M			
33	Thermal	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
34	Thermal Fuel (501)	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
35	Hydro	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption

Line	Account	Functional Category	Classification	Allocation	
	Production O&M (continued)				
1	Water for Power (536)	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
2	Other (Coyote Springs)	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
3	Other Fuel (547)	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
4	Other	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
5	Purchased Power and Other Expenses (555 and 557)	P = Production	Demand/Energy from Production Plant	S01	Sum of Production Plant
6	System Control & Misc (556)	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02	Coincident Peak Demand/Annual Generation Level Consumption
	Transmission O&M				
7	All Transmission	T = Transmission	Demand	D02	7 Month Average Coincident Peak Demand (4 Winter and 3 Summer Month Peaks)
	Distribution O&M				
8	580 OP Super & Engineering	D = Distribution	Demand/Customer from Other Dist Op Exp	S16	Sum of Other Distribution Operating Expenses
9	581 Load Dispatching	D = Distribution	Demand	D03	Non-coincident Peak Demand
10	582 Station Expenses	D = Distribution	Demand	S09	Sum of Account 362 Station Equipment
11	583 Overhead Lines	D = Distribution	Demand	S10	Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
12	584 Underground Lines	D = Distribution	Demand	S11	Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
13	585 Street Lights	D = Distribution	Customer	S15	Sum of Account 373 Street Light and Signal Systems
14	586 Meters	D = Distribution	Customer	S14	Sum of Account 370 Meters
15	587 Customer Installations	D = Distribution	Customer	S13	Sum of Account 369 Services
16	588 Misc Operating Expense	D = Distribution	Demand/Customer from Other Dist Op Exp	S16	Sum of Other Distribution Operating Expenses
17	589 Rents	D = Distribution	Demand	D03	Non-coincident Peak Demand
18	590 MT Super & Engineering	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17	Sum of Other Distribution Maintenance Expenses
19	591 MT of Structures	D = Distribution	Demand	S08	Sum of Account 361 Structures & Improvements
20	592 MT of Station Equipment	D = Distribution	Demand	S09	Sum of Account 362 Station Equipment
21	593 MT of Overhead Lines	D = Distribution	Demand	S10	Sum of Accounts 364 and 365 Poles, Towers, Fixtures & Overhead Conductors
22	594 MT of Underground Lines	D = Distribution	Demand	S11	Sum of Accounts 366 and 367 Underground Conduit & Underground Conductors
23	595 MT of Line Transformers	D = Distribution	Demand	S12	Sum of Account 368 Line Transformers
24	596 MT of Street Lights	D = Distribution	Customer	S15	Sum of Account 373 Street Light and Signal Systems
25	597 MT of Meters	D = Distribution	Customer	S14	Sum of Account 370 Meters
26	598 Misc Maintenance Expense	D = Distribution	Demand/Customer from Other Dist Mt Exp	S17	Sum of Other Distribution Maintenance Expenses
	Customer Accounts Expense				
27	901 Supervision	C = Customer Relations	Customer	S18	Sum of Other Customer Accounts Expenses Excluding Uncollectibles
28	902 Meter Reading	C = Customer Relations	Customer	C03	Customers Weighted by Estimated Meter Reading Time
29	903 Customer Records & Collections	C = Customer Relations	Customer	C01/C06	All Customers unweighted / Direct Assign Handbilled Cust
30	904 Uncollectible Accounts	R = Revenue Conversion	Revenue	R01	Retail Sales Revenue
31	905 Misc Cust Accounts	C = Customer Relations	Customer	C01	All Customers unweighted
	Customer Service & Info Expense				
32	907 Supervision	C = Customer Relations	Customer	C01	All Customers unweighted
33	908 Customer Assistance	C = Customer Relations	Customer	C01	All Customers unweighted
34	908 DSM Amortization Expenses	DSM	Demand/Energy from Production Plant	S01	Sum of Production Plant
35	909 Advertising	C = Customer Relations	Customer	C01	All Customers unweighted
36	910 Misc Cust Service & Info	C = Customer Relations	Customer	C01	All Customers unweighted
	Sales Expenses				
37	911 - 916	C = Customer Relations	Energy	E02	Annual Generation Level Consumption

IPUC Case No. AVU-E-10-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Electric Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 - 927 & 930 -935 Assigned to Production	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
2	920 - 927 & 930 -935 Assigned to Transmission	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
3	920 - 927 & 930 - 935 Assigned to Distribution	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
4	920 - 927 & 930 - 935 Assigned to Customer Relations	C = Customer Relations	Customer	C01 All Customers unweighted
5	920 - 935 Assigned to Other	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
6	928 FERC Commission Fees	P = Production	Energy	E02 Annual Generation Level Consumption
7	928 IPUC Commission Fees	R = Revenue Conversion	Revenue	R01 Retail Sales Revenue
	Depreciation & Amortization Expens			
8	Intangible	P/T/O	Demand/Energy/Customer as in related Plant	S01/S02/S23 Sum of Production Plant / Sum of Transmission Plant / Corp Cost Alloctor
9	Production	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
10	Transmission	T = Transmission	Demand	D02 7 Month Average Coincident Peak Demand (4 Winter and 3 Summer Month Peaks)
11	Distribution	D = Distribution	Demand/Customer as in related Plant	D03/D04/D05/D06/D07/D08/C02/C04/C05 - See Related Plant
12	General	O=Other	Demand/Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers
	Taxes			
13	Property Tax	P/T/D/O	Demand/Energy/Customer from Related Plant	S01/S02/S03/S04 Sums of Production / Transmission / Distribution / General Plant
14	State kWh Generation Taxes	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
15	Misc Production Taxes	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
16	Misc Distribution Taxes	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
17	Idaho State Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
18	Federal Income Tax	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
19	Deferred FIT	R = Revenue Conversion	Revenue	R03 Revenue less Expenses Before Income Taxes less Interest Expense
	Other Income Related Item:			
20	CS2 Levelized Return and Boulder Write-off Amort.	P = Production	Demand/Energy by Peak Credit (38.1% Demand)	D01/E02 Coincident Peak Demand/Annual Generation Level Consumption
	Operating Revenue:			
21	Sales of Electricity- Retail	R = Revenue from Rates	Revenue	Input Pro Forma Revenue per Revenue Study
22	Sales for Resale (447)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
23	Misc Service Revenue (451)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
24	Sales of Water & Water Power (453)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
25	Rent from Production Property (454)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
26	Rent from Distribution Property (454)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
27	Other Electric Revenues - Generation (456)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
28	Other Electric Revenues - Wheeling (456)	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
29	Other Electric Revenues - Energy Delivery (456)	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
30	Optional Renewable Revenue (Sch 95)	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
31	Montana Retail Revenue	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
	Salaries & Wages (allocation factor input			
	Operation & Maintenance Expenses			
32	Production Total	P = Production	Demand/Energy from Production Plant	S01 Sum of Production Plant
33	Transmission Total	T = Transmission	Demand/Energy from Transmission Plant	S02 Sum of Transmission Plant
34	Distribution Total	D = Distribution	Demand/Customer from Distribution Plant	S03 Sum of Distribution Plant
35	Customer Accounts Total	C = Customer Relations	Customer	S18 Sum of Other Customer Accounts Expenses Excluding Uncollectibles
36	Customer Service Total	C = Customer Relations	Customer	C01 All Customers unweighted
37	Sales Total	C = Customer Relations	Energy	E02 Annual Generation Level Consumption
38	Admin & General Total	O=Other	Energy/Customer by Corp Cost Allocator	S23 25% direct O&M, 25% direct labor, 25% net direct plant, 25% number of customers

Sumcost
Scenario: Company Base Case
Rev Peak Credit & Trans by Demand w 7CP
PROPOSED METHODOLOGY

AVISTA UTILITIES
Cost of Service Basic Summary
For the Twelve Months Ended December 31, 2009

Idaho Jurisdiction
Electric Utility

03-09-10

	(b) (c) (d) (e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	Description	System Total	Residential Service Sch 1	General Service Sch 11-12	Large Gen Service Sch 21-22	Extra Large Gen Service Sch 25	Extra Large Service CP Sch 25P	Pumping Service Sch 31-32	Street & Area Lights Sch 41-49
	Plant In Service								
1	Production Plant	382,726,000	138,076,219	37,390,129	81,414,777	27,914,925	90,519,888	6,263,583	1,146,479
2	Transmission Plant	170,049,000	70,622,984	17,520,718	35,508,635	11,426,915	32,620,274	2,165,658	183,816
3	Distribution Plant	410,445,000	206,186,645	56,987,812	99,180,942	9,287,227	2,268,277	15,505,289	21,028,809
4	Intangible Plant	46,342,000	19,036,977	4,896,903	9,143,825	2,941,567	9,221,331	792,967	308,430
5	General Plant	70,516,000	37,784,547	8,873,594	11,133,192	2,785,535	7,435,336	1,360,061	1,143,736
6	Total Plant In Service	1,080,078,000	471,707,372	125,669,156	236,381,370	54,356,168	142,065,106	26,087,557	23,811,270
	Accum Depreciation								
7	Production Plant	(152,862,000)	(55,148,088)	(14,933,738)	(32,517,325)	(11,149,311)	(36,153,936)	(2,501,695)	(457,908)
8	Transmission Plant	(58,268,000)	(24,199,261)	(6,003,547)	(12,167,182)	(3,915,480)	(11,177,473)	(742,072)	(62,985)
9	Distribution Plant	(129,591,000)	(64,259,461)	(16,546,189)	(30,894,151)	(2,772,170)	(808,124)	(4,740,513)	(9,570,391)
10	Intangible Plant	(9,222,000)	(4,241,422)	(1,047,002)	(1,678,888)	(499,265)	(1,495,438)	(164,941)	(95,045)
11	General Plant	(28,309,000)	(15,168,795)	(3,562,348)	(4,469,476)	(1,118,267)	(2,984,953)	(546,003)	(459,158)
12	Total Accumulated Depreciation	(378,252,000)	(163,017,026)	(42,092,825)	(81,727,021)	(19,454,493)	(52,619,923)	(8,695,224)	(10,645,488)
13	Net Plant	701,826,000	308,690,346	83,576,331	154,654,349	34,901,675	89,445,183	17,392,333	13,165,782
14	Accumulated Deferred FIT	(104,938,000)	(45,883,006)	(12,181,072)	(22,770,895)	(5,317,675)	(14,046,809)	(2,498,108)	(2,240,436)
15	Miscellaneous Rate Base	11,074,000	4,314,835	1,211,449	2,615,407	649,994	1,788,306	265,670	228,339
16	Total Rate Base	607,962,000	267,122,176	72,606,707	134,498,861	30,233,995	77,186,680	15,159,896	11,153,686
17	Revenue From Retail Rates	229,698,000	90,495,000	29,245,000	50,597,000	12,455,000	39,455,000	4,404,000	3,047,000
18	Other Operating Revenues	25,572,000	9,667,454	2,582,807	5,467,241	1,765,040	5,512,029	435,779	141,650
19	Total Revenues	255,270,000	100,162,454	31,827,807	56,064,241	14,220,040	44,967,029	4,839,779	3,188,650
	Operating Expenses								
20	Production Expenses	128,873,000	46,502,632	12,591,819	27,415,026	9,398,786	30,470,572	2,108,613	385,553
21	Transmission Expenses	9,720,000	4,036,809	1,001,484	2,029,673	653,162	1,864,575	123,789	10,507
22	Distribution Expenses	8,627,000	4,109,043	1,097,220	1,994,914	234,221	94,201	300,111	797,290
23	Customer Accounting Expenses	4,287,000	2,995,672	634,527	276,791	114,627	193,509	54,658	17,217
24	Customer Information Expenses	1,304,000	584,769	142,495	227,203	76,892	249,287	19,944	3,410
25	Sales Expenses	243,000	82,806	22,845	51,304	18,173	62,642	4,237	993
26	Admin & General Expenses	22,849,000	11,928,175	2,849,229	3,778,746	936,170	2,520,945	453,511	382,224
27	Total O&M Expenses	175,903,000	70,239,906	18,339,619	35,773,657	11,432,031	35,455,730	3,064,863	1,597,194
28	Taxes Other Than Income Taxes	7,760,000	3,179,533	852,734	1,697,298	451,380	1,290,565	166,909	121,581
29	Other Income Related Items	56,000	20,203	5,471	11,913	4,084	13,245	916	168
	Depreciation Expense								
30	Production Plant Depreciation	9,987,000	3,603,014	975,672	2,124,469	728,423	2,362,061	163,444	29,917
31	Transmission Plant Depreciation	3,442,000	1,429,496	354,641	718,738	231,295	660,274	43,836	3,721
32	Distribution Plant Depreciation	10,538,000	5,207,718	1,414,120	2,775,282	271,741	55,791	420,552	392,796
33	General Plant Depreciation	6,473,000	3,468,424	814,549	1,021,969	255,698	682,525	124,846	104,989
34	Amortization Expense	1,314,000	476,888	128,648	279,315	95,541	308,455	21,316	3,837
35	Total Depreciation Expense	31,754,000	14,185,540	3,687,630	6,919,773	1,582,697	4,069,107	773,994	535,259
36	Income Tax	8,265,000	1,679,198	2,639,878	2,955,713	(73,938)	688,647	143,261	232,241
37	Total Operating Expenses	223,738,000	89,304,381	25,525,332	47,358,353	13,396,255	41,517,294	4,149,943	2,486,442
38	Net Income	31,532,000	10,858,073	6,302,475	8,705,888	823,784	3,449,736	689,836	702,208
39	Rate of Return	5.19%	4.06%	8.68%	6.47%	2.72%	4.47%	4.55%	6.30%
40	Return Ratio	1.00	0.78	1.67	1.25	0.53	0.86	0.88	1.21
41	Interest Expense	18,847,000	8,280,866	2,250,829	4,169,504	937,263	2,392,810	469,961	345,768

Sumcost
Scenario: Company Base Case
Rev Peak Credit & Trans by Demand w 7CP
PROPOSED METHODOLOGY

AVISTA UTILITIES
Revenue to Cost by Functional Component Summary
For the Twelve Months Ended December 31, 2009

Idaho Jurisdiction
Electric Utility

03-09-10

	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Functional Cost Components at Current Return by Schedule											
1	Production				140,702,336	49,472,169	15,040,524	31,040,553	9,647,433	32,792,335	2,273,796	435,527
2	Transmission				16,818,902	6,332,864	2,337,424	3,994,383	879,550	3,050,148	204,163	20,369
3	Distribution				42,766,826	19,423,502	7,807,626	10,686,503	839,910	552,250	1,364,403	2,092,632
4	Common				29,409,935	15,266,465	4,059,425	4,875,560	1,088,107	3,060,267	561,638	498,473
5	Total Current Rate Revenue				229,698,000	90,495,000	29,245,000	50,597,000	12,455,000	39,455,000	4,404,000	3,047,000
	Expressed as $/kWh											
6	Production				$0.04127	$0.04294	$0.04732	$0.04338	$0.03729	$0.03675	$0.03857	$0.03152
7	Transmission				$0.00493	$0.00550	$0.00735	$0.00558	$0.00340	$0.00342	$0.00346	$0.00147
8	Distribution				$0.01254	$0.01686	$0.02456	$0.01493	$0.00325	$0.00062	$0.02314	$0.15146
9	Common				$0.00863	$0.01325	$0.01277	$0.00681	$0.00421	$0.00343	$0.00953	$0.03608
10	Total Current Melded Rates				$0.06737	$0.07854	$0.09200	$0.07070	$0.04814	$0.04422	$0.07470	$0.22054
	Functional Cost Components at Uniform Current Return											
11	Production				141,234,327	50,946,910	13,796,630	30,043,348	10,301,800	33,410,486	2,311,735	423,417
12	Transmission				17,056,053	7,083,543	1,757,342	3,561,545	1,146,129	3,271,840	217,217	18,437
13	Distribution				41,914,937	21,705,248	5,769,238	9,419,878	1,072,520	568,004	1,463,131	1,916,916
14	Common				29,492,684	15,739,415	3,705,448	4,696,604	1,171,675	3,124,750	572,200	482,591
15	Total Uniform Current Cost				229,698,000	95,475,116	25,028,659	47,721,374	13,692,124	40,375,081	4,564,284	2,841,361
	Expressed as $/kWh											
16	Production				$0.04142	$0.04422	$0.04340	$0.04198	$0.03982	$0.03744	$0.03921	$0.03065
17	Transmission				$0.00500	$0.00615	$0.00553	$0.00498	$0.00443	$0.00367	$0.00368	$0.00133
18	Distribution				$0.01229	$0.01884	$0.01815	$0.01316	$0.00415	$0.00064	$0.02482	$0.13875
19	Common				$0.00865	$0.01366	$0.01166	$0.00656	$0.00453	$0.00350	$0.00971	$0.03493
20	Total Current Uniform Melded Rates				$0.06737	$0.08286	$0.07874	$0.06669	$0.05292	$0.04525	$0.07742	$0.20566
21	**Revenue to Cost Ratio at Current Rates**				1.00	0.95	1.17	1.06	0.91	0.98	0.96	1.07
	Functional Cost Components at Proposed Return by Schedule											
22	Production				152,345,698	53,505,968	16,263,196	33,615,707	10,473,028	35,562,180	2,465,014	460,605
23	Transmission				21,960,878	8,386,679	2,907,737	5,112,393	1,215,968	4,043,754	269,976	24,372
24	Distribution				55,511,218	25,666,231	9,811,698	13,958,188	1,133,458	622,851	1,862,134	2,456,658
25	Common				31,994,206	16,560,122	4,407,369	5,337,712	1,193,546	3,349,215	614,876	531,365
26	Total Proposed Rate Revenue				261,812,000	104,119,000	33,390,000	58,024,000	14,016,000	43,578,000	5,212,000	3,473,000
	Expressed as $/kWh											
27	Production				$0.04468	$0.04644	$0.05116	$0.04697	$0.04048	$0.03985	$0.04181	$0.03334
28	Transmission				$0.00644	$0.00728	$0.00915	$0.00714	$0.00470	$0.00453	$0.00458	$0.00176
29	Distribution				$0.01628	$0.02228	$0.03087	$0.01950	$0.00438	$0.00070	$0.03159	$0.17781
30	Common				$0.00938	$0.01437	$0.01387	$0.00746	$0.00461	$0.00375	$0.01043	$0.03846
31	Total Proposed Melded Rates				$0.07679	$0.09037	$0.10504	$0.08108	$0.05418	$0.04884	$0.08840	$0.25138
	Functional Cost Components at Uniform Requested Return											
32	Production				152,814,458	55,124,679	14,927,942	32,506,713	11,146,421	36,149,344	2,501,252	458,106
33	Transmission				22,177,771	9,210,642	2,285,050	4,631,032	1,490,297	4,254,332	282,445	23,973
34	Distribution				54,731,378	28,170,731	7,623,598	12,549,570	1,372,832	637,815	1,956,436	2,420,396
35	Common				32,088,393	17,079,243	4,027,394	5,138,694	1,279,544	3,410,466	624,964	528,088
36	Total Uniform Cost				261,812,000	109,585,295	28,863,984	54,826,009	15,289,094	44,451,958	5,365,098	3,430,563
	Expressed as $/kWh											
37	Production				$0.04482	$0.04784	$0.04696	$0.04542	$0.04308	$0.04051	$0.04243	$0.03316
38	Transmission				$0.00650	$0.00799	$0.00719	$0.00647	$0.00576	$0.00477	$0.00479	$0.00174
39	Distribution				$0.01605	$0.02445	$0.02398	$0.01754	$0.00531	$0.00071	$0.03318	$0.17519
40	Common				$0.00941	$0.01482	$0.01267	$0.00718	$0.00495	$0.00382	$0.01060	$0.03822
41	Total Uniform Melded Rates				$0.07679	$0.09511	$0.09080	$0.07661	$0.05910	$0.04982	$0.09100	$0.24830
42	**Revenue to Cost Ratio at Proposed Rates**				1.00	0.95	1.16	1.06	0.92	0.98	0.97	1.01
43	**Current Revenue to Proposed Cost Ratio**				0.88	0.83	1.01	0.92	0.81	0.89	0.82	0.89

Sumcost
Scenario: Company Base Case
AVU-E-04-01 Method

AVISTA UTILITIES
Revenue to Cost By Classification Summary
For the Twelve Months Ended September 30, 2008

Idaho Jurisdiction
Electric Utility

01-15-09

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service Potlatch Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Cost Classifications at Current Return by Schedule									
1	Energy		94,641,059	31,447,737	9,736,552	20,726,579	6,656,502	24,044,500	1,629,820	399,369
2	Demand		113,959,079	44,883,443	15,291,873	29,190,347	5,713,427	15,399,192	2,498,111	982,687
3	Customer		21,097,862	14,163,820	4,216,574	680,075	85,071	11,308	276,070	1,664,944
4	Total Current Rate Revenue		229,698,000	90,495,000	29,245,000	50,597,000	12,455,000	39,455,000	4,404,000	3,047,000
	Expressed as Unit Cost									
5	Energy	$/kWh	$0.02776	$0.02729	$0.03063	$0.02896	$0.02573	$0.02695	$0.02764	$0.02891
6	Demand	$/kW/mo	$15.37	$16.02	$20.37	$16.67	$11.81	$11.56	$9.97	$21.86
7	Customer	$/Cust/mo	$14.44	$11.85	$18.26	$38.90	$886.16	$942.30	$17.53	$1,128.01
	Cost Classifications at Uniform Current Return									
8	Energy		95,026,548	32,381,930	8,933,769	20,062,820	7,106,464	24,496,345	1,656,928	388,292
9	Demand		113,709,888	48,138,461	12,633,178	27,059,995	6,496,373	15,867,241	2,617,100	897,540
10	Customer		20,961,564	14,954,725	3,461,712	598,559	89,287	11,495	290,256	1,555,530
11	Total Uniform Current Cost		229,698,000	95,475,116	25,028,659	47,721,374	13,692,124	40,375,081	4,564,284	2,841,361
	Expressed as Unit Cost									
12	Energy	$/kWh	$0.02787	$0.02810	$0.02810	$0.02804	$0.02747	$0.02745	$0.02810	$0.02810
13	Demand	$/kW/mo	$15.34	$17.19	$16.83	$15.45	$13.42	$11.91	$10.45	$19.97
14	Customer	$/Cust/mo	$14.35	$12.51	$14.99	$34.23	$930.08	$957.88	$18.43	$1,053.88
15	Revenue to Cost Ratio at Current Rates		1.00	0.95	1.17	1.06	0.91	0.98	0.96	1.07
	Cost Classifications at Proposed Return by Schedule									
16	Energy		102,451,394	34,002,994	10,525,638	22,440,649	7,224,205	26,069,148	1,766,450	422,311
17	Demand		134,842,071	53,788,519	17,905,670	34,692,722	6,701,405	17,496,707	3,097,964	1,159,084
18	Customer		24,518,535	16,327,487	4,958,693	890,629	90,390	12,145	347,587	1,891,605
19	Total Proposed Rate Revenue		261,812,000	104,119,000	33,390,000	58,024,000	14,016,000	43,578,000	5,212,000	3,473,000
	Expressed as Unit Cost									
20	Energy	$/kWh	$0.03005	$0.02951	$0.03311	$0.03136	$0.02792	$0.02922	$0.02996	$0.03057
21	Demand	$/kW/mo	$18.19	$19.20	$23.86	$19.81	$13.85	$13.13	$12.36	$25.78
22	Customer	$/Cust/mo	$16.79	$13.66	$21.47	$50.94	$941.56	$1,012.10	$22.07	$1,281.57
	Cost Classifications at Uniform Requested Return									
23	Energy		102,792,720	35,028,387	9,663,893	21,702,481	7,687,249	26,498,342	1,792,343	420,025
24	Demand		134,538,100	57,361,305	15,051,703	32,323,553	7,507,116	17,941,293	3,211,618	1,141,513
25	Customer		24,481,180	17,195,603	4,148,388	799,975	94,729	12,323	361,137	1,869,025
26	Total Uniform Cost		261,812,000	109,585,295	28,863,984	54,826,009	15,289,094	44,451,958	5,365,098	3,430,563
	Expressed as Unit Cost									
27	Energy	$/kWh	$0.03015	$0.03040	$0.03040	$0.03033	$0.02971	$0.02970	$0.03040	$0.03040
28	Demand	$/kW/mo	$18.15	$20.48	$20.05	$18.46	$15.51	$13.47	$12.82	$25.39
29	Customer	$/Cust/mo	$16.76	$14.39	$17.96	$45.75	$986.76	$1,026.89	$22.94	$1,266.28
30	Revenue to Cost Ratio at Proposed Rates		1.00	0.95	1.16	1.06	0.92	0.98	0.97	1.01
31	Current Revenue to Proposed Cost Ratio		0.88	0.83	1.01	0.92	0.81	0.89	0.82	0.89

Sumcost
Scenario: Company Base Case
Rev Peak Credit & Trans by Demand w 7CP
PROPOSED METHODOLOGY

AVISTA UTILITIES
Customer Cost Analysis
For the Twelve Months Ended December 31, 2009

Idaho Jurisdiction
Electric Utility

03-09-10

	(b) Description	(c) (d) (e)	(f) System Total	(g) Residential Service Sch 1	(h) General Service Sch 11-12	(i) Large Gen Service Sch 21-22	(j) Extra Large Gen Service Sch 25	(k) Extra Large Service CP Sch 25P	(l) Pumping Service Sch 31-32	(m) Street & Area Lights Sch 41-49
	Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return									
	Rate Base									
1	Services		43,010,000	35,231,923	6,808,946	504,880	0	0	464,251	0
2	Services Accum. Depr.		(15,854,000)	(12,986,908)	(2,509,859)	(186,105)	0	0	(171,128)	0
3	Total Services		27,156,000	22,245,015	4,299,087	318,775	0	0	293,123	0
4	Meters		28,499,000	15,036,787	8,398,398	3,878,773	78,316	12,995	1,093,731	0
5	Meters Accum. Depr.		(1,938,000)	(1,022,537)	(571,111)	(263,766)	(5,326)	(884)	(74,376)	0
6	Total Meters		26,561,000	14,014,249	7,827,287	3,615,008	72,990	12,112	1,019,355	0
7	Total Rate Base		53,717,000	36,259,265	12,126,374	3,933,783	72,990	12,112	1,312,477	0
8	Return on Rate Base @ 8.55%		4,592,804	3,100,167	1,036,805	336,338	6,241	1,036	112,217	0
9	Revenue Conversion Factor		0.63676	0.63676	0.63676	0.63676	0.63676	0.63676	0.63676	0.63676
10	**Rate Base Revenue Requirement**		**7,212,770**	**4,868,659**	**1,628,251**	**528,203**	**9,801**	**1,626**	**176,231**	**0**
	Expenses									
11	Services Depr Exp		670,000	548,835	106,068	7,865	0	0	7,232	0
12	Meters Depr Exp		389,000	205,246	114,635	52,944	1,069	177	14,929	0
13	Services Operations Exp		418,000	342,407	66,174	4,907	0	0	4,512	0
14	Meters Operating Exp		141,000	74,395	41,551	19,190	387	64	5,411	0
15	Meters Maintenance Exp		39,000	20,577	11,493	5,308	107	18	1,497	0
16	Meter Reading		368,000	274,231	52,998	4,012	29,462	3,683	3,614	0
17	Billing		2,553,000	2,067,638	399,593	30,253	22,859	2,857	27,245	2,554
18	Total Expenses		4,578,000	3,533,330	792,513	124,479	53,885	6,800	64,440	2,554
19	Revenue Conversion Factor		0.99384	0.99384	0.99384	0.99384	0.99384	0.99384	0.99384	0.99384
20	**Expense Revenue Requirement**		**4,606,375**	**3,555,231**	**797,425**	**125,250**	**54,219**	**6,842**	**64,839**	**2,570**
21	**Total Meter, Service, Meter Reading, and**		**11,819,145**	**8,423,889**	**2,425,675**	**653,453**	**64,020**	**8,468**	**241,070**	**2,570**
22	Total Customer Bills		1,460,714	1,194,961	230,939	17,484	96	12	15,746	1,476
23	**Average Unit Cost per Month**		**$8.09**	**$7.05**	**$10.50**	**$37.37**	**$666.87**	**$705.67**	**$15.31**	**$1.74**
	Distribution Fixed Costs per Customer									
24	Total Customer Related Cost		24,481,180	17,195,603	4,148,388	799,975	94,729	12,323	361,137	1,869,025
25	Customer Related Unit Cost per Month		$16.76	$14.39	$17.96	$45.75	$986.76	$1,026.89	$22.94	$1,266.28
26	Total Distribution Demand Related Cost		46,175,332	22,022,546	5,896,850	13,406,248	1,405,515	436,749	1,959,916	1,047,508
27	Dist Demand Related Unit Cost per Month		$31.61	$18.43	$25.53	$766.77	$14,640.78	$36,395.71	$124.47	$709.69
28	**Total Distribution Unit Cost per Month**		**$48.37**	**$32.82**	**$43.50**	**$812.53**	**$15,627.54**	**$37,422.61**	**$147.41**	**$1,975.97**

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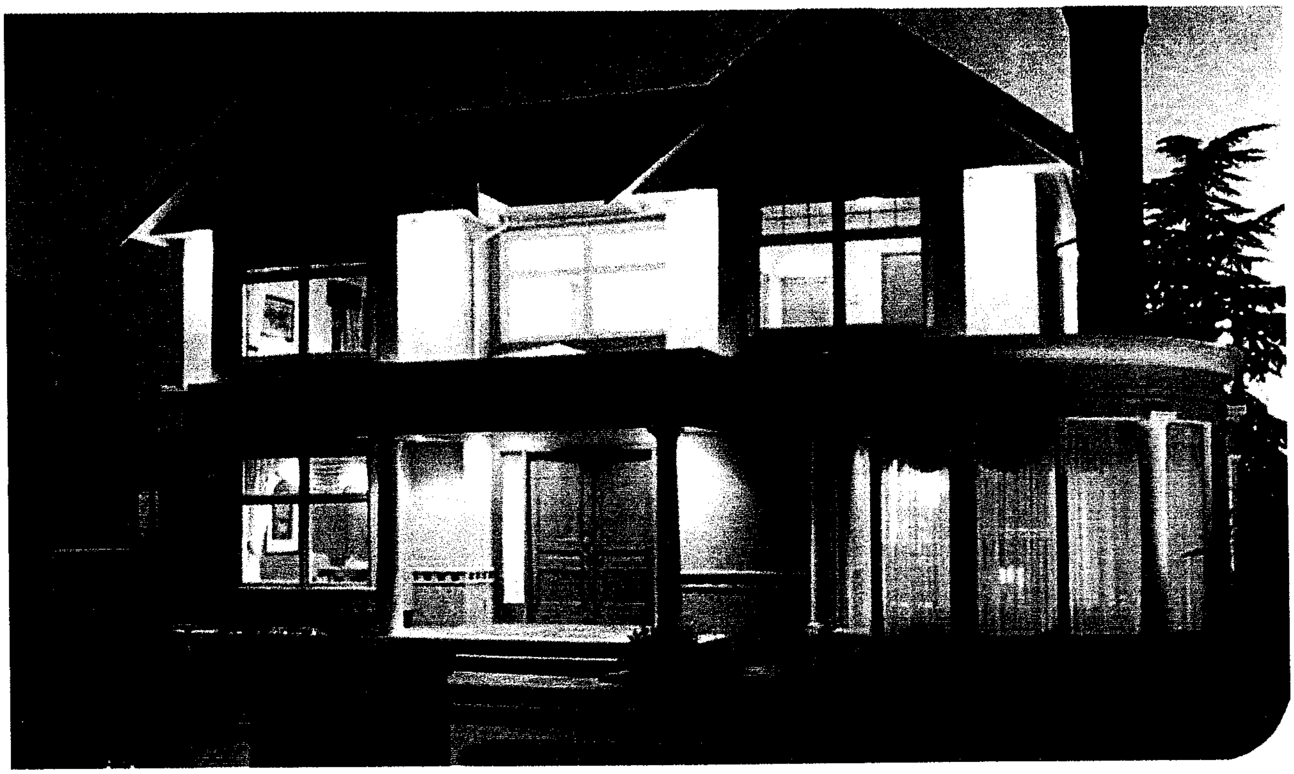
System Load Research Project



Examining the components of the Avista system load

Avista Corp., Spokane, Washington, March 2010

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1. Executive Summary

1.1 Project Overview

In this project *KEMA* provided assistance to Avista in developing hourly load estimates for Avista rate classes. The analysis detailed in this report focuses on data collected for the 12-month period January 1, 2009 through December 31, 2009. The primary objective of the overall analysis is to develop hourly class load estimates for use in cost allocation, i.e., to develop factors to allocate generation, transmission, and distribution costs to each rate class for cost-of-service purposes.

In order to perform the analysis, Avista provided 60-minute interval load profile data for each customer class. Some customer class loads were estimated using load study samples (when it is not practical to collect load profile data for every customer within the class). The 60-minute load profile load data for these schedules were for specific customers who were randomly selected to be part of a load study.

The load study samples were designed with KEMA's assistance to be representative of Avista's customer classes throughout Avista's service territory (both Washington and Idaho) at a generally-accepted level of statistical precision (confidence that the demand estimates calculated using samples are within ten percent of the "true" population demand for a majority of hours). These samples were used to conduct the load research expansion analysis (that is, estimate the population loads from the sample loads). This project provided statistically reliable data allowing the researchers to develop independent estimates for each class within each jurisdiction.

In addition to the load study samples, some customer classes have hourly load data for all customers in the class (these tend to be large customers, and their load profile data is used for billing purposes). Finally, the project team estimated total class hourly loads for the lighting class based on lighting inventories, daylight hours and sunrise/sunset schedules.

Avista also provided hourly total system load data. Figure 1 shows a vertical EnergyPrint and a two-dimensional time series plot of the Avista system load during the 12-month period ending December 31, 2009. In a vertical energy print, the days are measured on the y-axis and hours of the day on the x-axis. The load is displayed using the color scale shown to the left of the plot. The energy print provides an overview of a load profile. In this case the energy print shows that the Avista system load is winter peaking with the highest demands in the morning (i.e., 6 AM to

11 AM) and evening periods (i.e., 5 PM to 10 PM) during the winter months. The system peaked at 1,763 MW on Tuesday, December 8, 2009 at hour ending 7 PM.

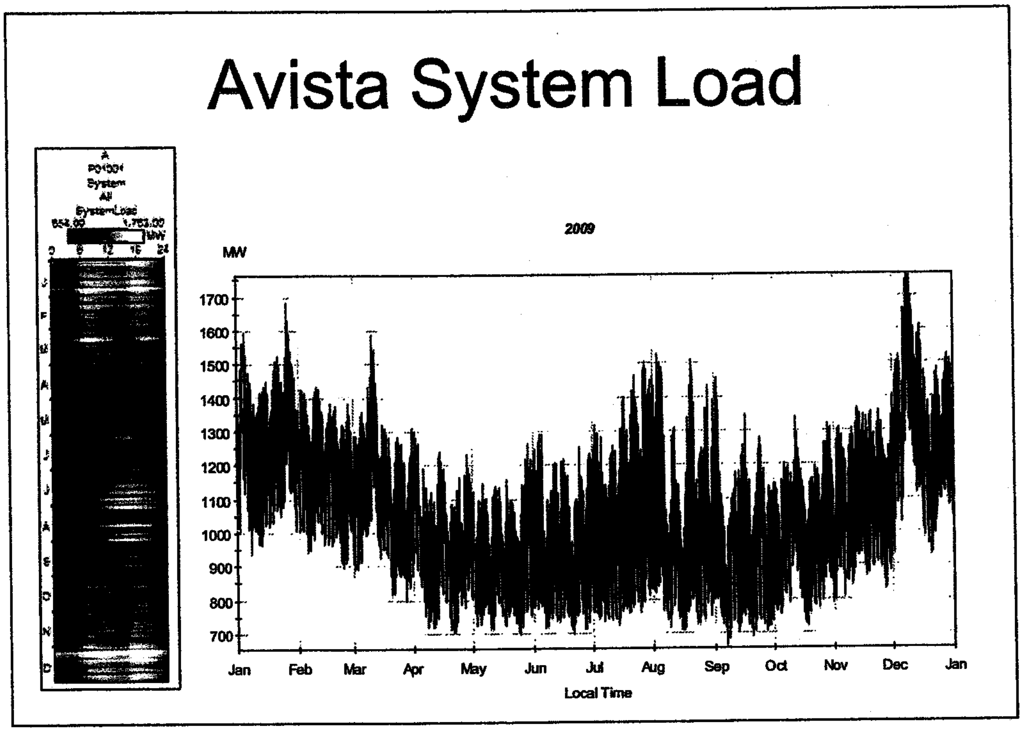

Figure 1 – System Load

The results of this analysis include each customer class's contribution (delivered load plus losses) to Avista's total system hourly demands for the period January 1, 2009 to December 31, 2009. From these results, various energy- and demand-related statistics can be calculated reliably for cost allocation purposes.

1.2 Key Statistics

Table 1 presents a summary of population and energy characteristics for the aggregate classes within the Washington and Idaho jurisdictions. The table includes the total number of customers and annual energy consumption by rate class. In addition, the table includes each rate schedule's contribution to the total for each jurisdiction (Washington and Idaho) and each rate schedule's contribution to the overall Avista total.

Jurisdiction	Rate Code	Class	No. of Customers Count	% of Juris. Total	% of Avista Total	Annual Usage kWh	% of Juris. Total	% of Avista Total
Washington	001	Residential	200,134	85.9%	56.4%	2,631,728,751	45.0%	27.8%
Washington	011/012	General Service	27,142	11.6%	7.7%	446,213,347	7.6%	4.7%
Washington	021/022	Large General Service	3,352	1.4%	0.9%	1,668,039,904	28.5%	17.6%
Washington	025	Extra Large General Service	22	0.0%	0.0%	923,220,330	15.8%	9.7%
Washington	031/032	Pumping	2,361	1.0%	0.7%	147,043,989	2.5%	1.6%
Washington	LGT	Street and Area Lights*	-	0.0%	0.0%	28,458,151	0.5%	0.3%
		TOTAL WASHINGTON	233,010	100.0%	65.7%	5,844,704,472	100.0%	61.6%
Idaho	001	Residential	99,580	81.9%	28.1%	1,268,698,311	34.9%	13.4%
Idaho	011/012	General Service	19,245	15.8%	5.4%	346,190,462	9.5%	3.7%
Idaho	021/022	Large General Service	1,458	1.2%	0.4%	755,816,002	20.8%	8.0%
Idaho	25	Extra Large General Service	8	0.0%	0.0%	272,685,547	7.5%	2.9%
Idaho	25P	Extra Large General Service - CP	1	0.0%	0.0%	916,049,902	25.2%	9.7%
Idaho	031/032	Pumping	1,312	1.1%	0.4%	63,429,201	1.7%	0.7%
Idaho	LGT	Street and Area Lights*	-	0.0%	0.0%	14,832,897	0.4%	0.2%
		TOTAL IDAHO	121,604	100.0%	34.3%	3,637,702,321	100.0%	38.4%
		TOTAL AVISTA	354,614		100.0%	9,482,406,794		100.0%

*Note: Street and area light customer counts are not included since lighting customers are counted in a different manner than the rest of the classes (i.e., contracts and/or number of lights).

Table 1 – Number of Customers and Annual Usage

Table 2 presents the class demand at the time of the annual system peak which occurred on Tuesday, December 8, 2009, at hour ending 7 PM. The dominance of the residential class is evident accounting for nearly 1,000 MW of the 1,763 MW Avista system peak demand. The large general service class is next in order of magnitude of load with nearly 350 MW at the time of the Avista peak.

State	Rate Code	Class	System Peak (kW)	% of Juris. Total	% of Avista Total
Washington	001	Residential	709,854	61.4%	40.3%
Washington	011/012	General Service	63,841	5.5%	3.6%
Washington	021/022	Large General Service	232,316	20.1%	13.2%
Washington	025	Extra Large General Service	133,699	11.6%	7.6%
Washington	031/032	Pumping	9,900	0.9%	0.6%
Washington	LGT	Street and Area Lights	6,832	0.6%	0.4%
		TOTAL WASHINGTON	1,156,441	100.0%	65.6%
Idaho	001	Residential	282,619	46.6%	16.0%
Idaho	011/012	General Service	61,401	10.1%	3.5%
Idaho	021/022	Large General Service	114,858	18.9%	6.5%
Idaho	25	Extra Large General Service	39,605	6.5%	2.2%
Idaho	25P	Extra Large General Service - CP	100,671	16.6%	5.7%
Idaho	031/032	Pumping	3,853	0.6%	0.2%
Idaho	LGT	Street and Area Lights	3,551	0.6%	0.2%
		TOTAL IDAHO	606,559	100.0%	34.4%
		TOTAL AVISTA	1,763,000		100.0%

Table 2 – Class Demand at Annual System Peak

Table 3 presents the annual class peak demands including the date and time of the class peak. In addition, the table includes each rate schedule's contribution to the total of the class peak demands for each jurisdiction (Washington and Idaho) and each rate schedule's contribution to the overall Avista total[1].

State	Rate Code	Class	Class Peak Demand Date & Time	(kW)	% of Juris. Total	% of Avista Total
Washington	001	Residential	Tue Dec 8, 2009 7:00PM	709,854	53.2%	33.8%
Washington	011/012	General Service	Mon Aug 3, 2009 4:00PM	97,046	7.3%	4.6%
Washington	021/022	Large General Service	Wed Sep 16, 2009 4:00PM	323,832	24.3%	15.4%
Washington	025	Extra Large General Service	Tue Dec 8, 2009 12:00PM	145,722	10.9%	6.9%
Washington	031/032	Pumping	Fri Jun 5, 2009 6:00PM	49,140	3.7%	2.3%
Washington	LGT	Street and Area Lights	Wed Jan 7, 2009 9:00PM	7,493	0.6%	0.4%
		TOTAL WASHINGTON		1,333,088	100.0%	63.5%
Idaho	001	Residential	Sun Dec 6, 2009 8:00PM	319,343	41.7%	15.2%
Idaho	011/012	General Service	Wed Dec 9, 2009 5:00PM	76,509	10.0%	3.6%
Idaho	021/022	Large General Service	Tue Aug 4, 2009 3:00PM	162,924	21.3%	7.8%
Idaho	25	Extra Large General Service	Wed Sep 2, 2009 1:00PM	41,917	5.5%	2.0%
Idaho	25P	Extra Large General Service - CP	Wed Dec 16, 2009 1:00AM	112,705	14.7%	5.4%
Idaho	031/032	Pumping	Fri Jul 24, 2009 8:00AM	48,192	6.3%	2.3%
Idaho	LGT	Street and Area Lights	Wed Jan 7, 2009 9:00PM	3,895	0.5%	0.2%
		TOTAL IDAHO		765,484	100.0%	36.5%
		TOTAL AVISTA		2,098,572		100.0%

Table 3 –Annual Class Peak Demand

[1] The sum of the class peak demands is not a demand that actually occurred on the system, however, each class's contribution to the total of the class peak demands is used for cost allocation purposes so is included as a key statistic.

Table 4 presents the annual maximum non-coincident class peak demand which is the "theoretical" or potential maximum demand of the class if all individual customers peaked at the same time.

State	Rate Code	Class	Non-Coincident Peak Demand (kW)	% of Juris. Total	% of Avista Total
Washington	001	Residential	1,908,605	66.5%	42.9%
Washington	011/012	General Service	229,430	8.0%	5.2%
Washington	021/022	Large General Service	476,575	16.6%	10.7%
Washington	025	Extra Large General Service	177,799	6.2%	4.0%
Washington	031/032	Pumping	70,203	2.4%	1.6%
Washington	LGT	Street and Area Lights	7,493	0.3%	0.2%
		TOTAL WASHINGTON	2,870,106	100.0%	64.5%
Idaho	001	Residential	916,236	57.9%	20.6%
Idaho	011/012	General Service	159,227	10.1%	3.6%
Idaho	021/022	Large General Service	226,444	14.3%	5.1%
Idaho	25	Extra Large General Service	48,090	3.0%	1.1%
Idaho	25P	Extra Large General Service - CP	172,142	10.9%	3.9%
Idaho	031/032	Pumping	56,742	3.6%	1.3%
Idaho	LGT	Street and Area Lights	3,895	0.2%	0.1%
		TOTAL IDAHO	1,582,777	100.0%	35.5%
		TOTAL AVISTA	4,452,883		100.0%

Table 4 – Annual Non-coincident Peak Demand

Table 5 and Table 6 present selected allocators (kW and %) for each class by jurisdiction and total system. The allocators included in Table 5 are the average 12-month class peak demand and the average 12-month system peak demand.

State	Rate Code	Class	12-Month Class Peak (kW)	% of Juris. Total	% of Avista Total	12-Month System Peak (kW)	% of Juris. Total	% of Avista Total
Washington	001	Residential	506,175	48.3%	30.4%	463,575	49.8%	31.8%
Washington	011/012	General Service	88,013	8.4%	5.3%	75,348	8.1%	5.2%
Washington	021/022	Large General Service	287,992	27.5%	17.3%	252,577	27.1%	17.3%
Washington	025	Extra Large General Service	131,145	12.5%	7.9%	118,996	12.8%	8.2%
Washington	031/032	Pumping	27,840	2.7%	1.7%	18,890	2.0%	1.3%
Washington	LGT	Street and Area Lights	7,189	0.7%	0.4%	1,138	0.1%	0.1%
		TOTAL WASHINGTON	1,048,354	100.0%	62.9%	930,524	100.0%	63.8%
Idaho	001	Residential	233,419	37.8%	14.0%	207,604	39.3%	14.2%
Idaho	011/012	General Service	62,548	10.1%	3.8%	54,729	10.4%	3.8%
Idaho	021/022	Large General Service	145,915	23.6%	8.8%	113,663	21.5%	7.8%
Idaho	25	Extra Large General Service	40,327	6.5%	2.4%	36,919	7.0%	2.5%
Idaho	25P	Extra Large General Service - CP	111,015	18.0%	6.7%	106,611	20.2%	7.3%
Idaho	031/032	Pumping	20,880	3.4%	1.3%	7,721	1.5%	0.5%
Idaho	LGT	Street and Area Lights	3,746	0.6%	0.2%	646	0.1%	0.0%
		TOTAL IDAHO	617,849	100.0%	37.1%	527,893	100.0%	36.2%
		TOTAL AVISTA	1,666,204		100.0%	1,458,417		100.0%

Table 5 – Average 12-Month Class Peak Demand and 12-Month System Peak Demand

Table 6 includes the average of the four winter peaks and the average of the four winter peaks and the three summer peaks.

State	Rate Code	Class	4-Month Winter Peak (kW)	4-Month Winter Peak % of Juris. Total	4-Month Winter Peak % of Avista Total	7-Month Summer/Winter Peak (kW)	7-Month Summer/Winter Peak % of Juris. Total	7-Month Summer/Winter Peak % of Avista Total
Washington	001	Residential	589,872	56.8%	36.6%	524,033	52.1%	33.6%
Washington	011/012	General Service	73,162	7.0%	4.5%	79,110	7.9%	5.1%
Washington	021/022	Large General Service	242,353	23.4%	15.0%	262,058	26.0%	16.8%
Washington	025	Extra Large General Service	122,613	11.8%	7.6%	122,469	12.2%	7.8%
Washington	031/032	Pumping	8,134	0.8%	0.5%	17,720	1.8%	1.1%
Washington	LGT	Street and Area Lights	1,708	0.2%	0.1%	976	0.1%	0.1%
		TOTAL WASHINGTON	1,037,842	100.0%	64.3%	1,006,366	100.0%	64.5%
Idaho	001	Residential	254,637	44.2%	15.8%	230,523	41.5%	14.8%
Idaho	011/012	General Service	59,300	10.3%	3.7%	57,190	10.3%	3.7%
Idaho	021/022	Large General Service	113,771	19.8%	7.1%	115,905	20.9%	7.4%
Idaho	25	Extra Large General Service	37,554	6.5%	2.3%	37,299	6.7%	2.4%
Idaho	25P	Extra Large General Service - CP	104,793	18.2%	6.5%	106,477	19.2%	6.8%
Idaho	031/032	Pumping	4,803	0.8%	0.3%	7,069	1.3%	0.5%
Idaho	LGT	Street and Area Lights	1,049	0.2%	0.1%	600	0.1%	0.0%
		TOTAL IDAHO	575,908	100.0%	35.7%	555,062	100.0%	35.5%
		TOTAL AVISTA	1,613,750		100.0%	1,561,429		100.0%

Table 6 - Average 4-Month Winter Class Peak Demand and 7-Month Summer/Winter Peak Demand

Table 7 presents additional allocators based on the performance of the class at selected system peak hours. The first allocator is based on the top 25 system load hours followed by the top 75 and the top 200 hours.

State	Rate Code	Class	Top 25 System Hours (kW)	Top 25 % of Juris. Total	Top 25 % of Avista Total	Top 75 System Hours (kW)	Top 75 % of Juris. Total	Top 75 % of Avista Total	Top 200 System Hours (kW)	Top 200 % of Juris. Total	Top 200 % of Avista Total
Washington	001	Residential	634,251	57.7%	37.2%	593,248	56.4%	36.1%	545,831	54.7%	35.0%
Washington	011/012	General Service	75,829	6.9%	4.4%	75,420	7.2%	4.6%	73,071	7.3%	4.7%
Washington	021/022	Large General Service	242,355	22.1%	14.2%	241,900	23.0%	14.7%	238,831	24.0%	15.3%
Washington	025	Extra Large General Service	131,211	11.9%	7.7%	127,971	12.2%	7.8%	124,560	12.5%	8.0%
Washington	031/032	Pumping	10,186	0.9%	0.6%	10,092	1.0%	0.6%	11,293	1.1%	0.7%
Washington	LGT	Street and Area Lights	4,481	0.4%	0.3%	3,677	0.3%	0.2%	3,526	0.4%	0.2%
		TOTAL WASHINGTON	1,098,313	100.0%	64.4%	1,052,307	100.0%	64.1%	997,112	100.0%	63.9%
Idaho	001	Residential	275,125	45.3%	16.1%	262,265	44.5%	16.0%	244,567	43.4%	15.7%
Idaho	011/012	General Service	63,115	10.4%	3.7%	62,242	10.6%	3.8%	59,478	10.6%	3.8%
Idaho	021/022	Large General Service	117,480	19.3%	6.9%	114,562	19.4%	7.0%	110,411	19.6%	7.1%
Idaho	25	Extra Large General Service	38,715	6.4%	2.3%	37,346	6.3%	2.3%	36,320	6.4%	2.3%
Idaho	25P	Extra Large General Service - CP	105,514	17.4%	6.2%	105,593	17.9%	6.4%	105,345	18.7%	6.8%
Idaho	031/032	Pumping	5,478	0.9%	0.3%	5,302	0.9%	0.3%	5,551	1.0%	0.4%
Idaho	LGT	Street and Area Lights	2,420	0.4%	0.1%	1,982	0.3%	0.1%	1,801	0.3%	0.1%
		TOTAL IDAHO	607,847	100.0%	35.6%	589,293	100.0%	35.9%	563,473	100.0%	36.1%
		TOTAL AVISTA	1,706,160		100.0%	1,641,600		100.0%	1,560,585		100.0%

Table 7 – Summary of Top System Hours

2. Management Report

2.1 Introduction

2.1.1 Background

In this project *KEMA* provided assistance to Avista in developing hourly load estimates for various customer classes. The primary goal is to use the results of this load research analysis in the Company's upcoming cost-of-service (COS) analysis. Table 8 presents the customer classes included in the analysis.

State	Rate Code	Class
Washington	001	Residential
Washington	011/012	General Service
Washington	021/022	Large General Service
Washington	025	Extra Large General Service
Washington	031/032	Pumping
Washington	LGT	Street and Area Lights
Idaho	001	Residential
Idaho	011/012	General Service
Idaho	021/022	Large General Service
Idaho	25	Extra Large General Service
Idaho	25P	Extra Large General Service - CP
Idaho	031/032	Pumping
Idaho	LGT	Street and Area Lights

Table 8 – Rate Classes Analyzed

The Company collects 15-minute load profile data for residential, commercial and industrial customers. Primarily, the data are collected by the Company's conventional metering following a statistically stratified sample design. These data are assembled, edited and stored by the Company in the MV90 system and transferred to KEMA for analysis. KEMA conducts a secondary review of the data and transfers the information into Statistical Analysis System (SAS) files.

The analysis detailed in this report focuses on data collected for the 12-month period January 1, 2009 through December 31, 2009. The primary objective of the overall analysis is to develop hourly class load estimates for use in cost allocation, i.e., to develop factors to allocate generation, transmission, and distribution costs to each rate schedule for cost-of-service purposes.

2.1.2 Project Deliverables

The project deliverables include the following:

- An analysis-ready (i.e., validated and edited) dataset suitable for use in the load research expansion analysis.

- A dataset containing class total hourly loads calculated for each class and sector specified in Table 8 either using load study sample data or hourly data for the entire customer class, when available, for the following scenarios:
  - Class hourly loads (before losses and not reconciled to hourly system load);
  - Class hourly loads with losses (not reconciled to hourly system load); and
  - Class hourly loads with losses and reconciled to hourly system load.

- Documentation of load research expansion analysis including:
  - General class statistics;
  - Post-stratification statistics;
  - Comparison of winter and summer average load profiles;
  - Comparison of weekday, weekend, and peak day average profiles;
  - Relative precision of load data used to calculate class estimates; and
  - Class peak (coincident and non-coincident with system) statistics including kW demand, load factor, and coincident factor.

- A series of tables depicting the class contributions for specific cost-of-service calculations including:
  - Class peak at the time of the annual system peak (i.e., coincident peak);
  - Annual class peak (peak times vary, not necessarily coincident with system peak);
  - Annual non-coincident class peak (i.e., hypothetical total class peak if all customers within the class peaked at the same time);
  - Average 12-month class peak;
  - Average 12-month system peak;
  - Average of the four winter peaks;

- Average of the four winter peaks and the three summer peaks;
- Average of the class peaks for the top 25, 75, and 200 system hours;
- Monthly coincident peaks;
- Monthly non-coincident peaks;
- Monthly load factors; and
- On-peak and off-peak energy by month.

2.1.3 Data Provided by Avista

In order to perform our analysis, Avista provided 60-minute interval load profile data for each customer class. Some customer class loads were estimated using load study samples (when it is not practical to collect load profile data for every customer within the class). The 60-minute load profile load data for these schedules were for specific customers who were selected to be part of a load study. These load study samples were used to conduct our load research expansion analysis.

Some customer classes have load profile data for all customers (these tend to be large customers, and their load profile data is used for billing purposes). Examples include a number of the large power classes including Extra Large General Service. The project team estimated total class hourly loads for their lighting schedules based on lighting inventories, daylight hours and sunrise/sunset schedules.

In addition to customer-level or class-level interval data, Avista provided hourly total system load data. All load profile data provided was for the period January 1, 2009 to December 31, 2009.

Avista also provided additional supporting information such as total monthly and annual energy by schedule, customer counts, and annual loss factors by voltage level.

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2.1.4 Avista System Load Characteristics

Figure 2 shows a vertical EnergyPrint and a two-dimensional time series plot of the Avista system load during the 12-month period ending December 31, 2009. In a vertical energy print, the days are measured on the y-axis and hours of the day on the x-axis. The load is displayed using the color scale shown to the left of the plot. The energy print provides an overview of a load profile. In this case the energy print shows that the Avista system load is winter peaking with the highest demands in the morning (i.e., 6 AM to 11 AM) and evening periods (i.e., 5 PM to 10 PM) during the winter months. The system peaked at 1,763 MW on Tuesday, December 8, 2009 at hour ending 7 PM.

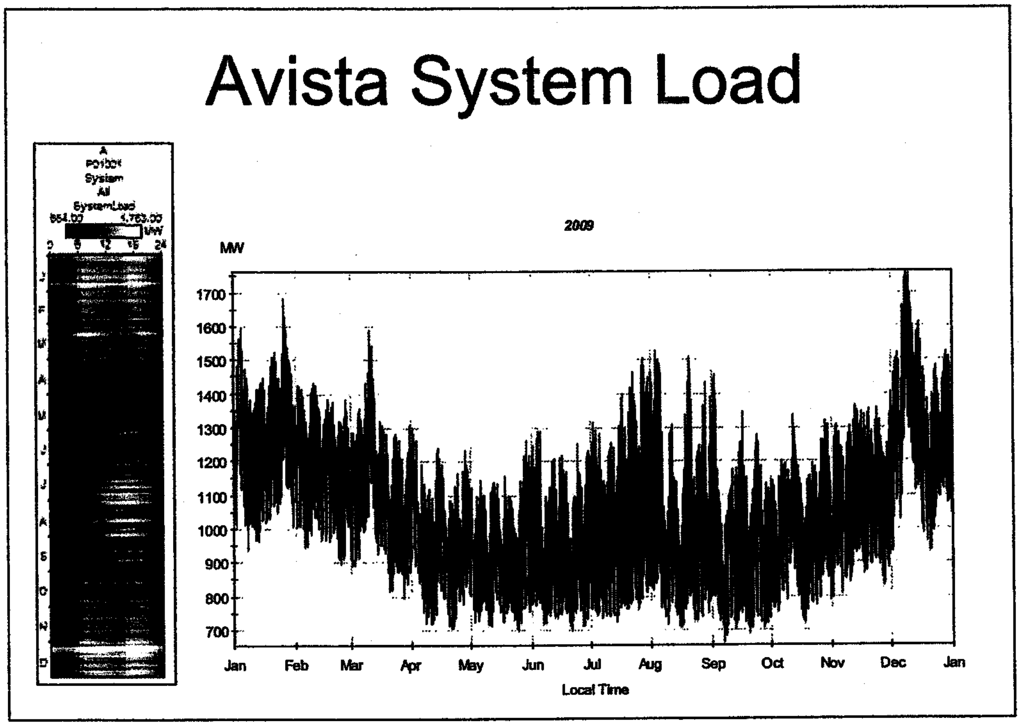


Figure 2 – Avista System Load Characteristics

Table 9 summarizes the monthly statistics from the system load for the 12 months ending December 31, 2009. The total monthly peak demand varied from a low of 1,258 MW in May to the high of 1,763 MW in December. The annual system peak occurred on Tuesday, December 8 at hour ending 7 PM. The monthly load factor of the system varied from 66.8% to 83.0%.

Month	Monthly Usage (MWh)	System Peak Date & Time	System Peak (MW)	Average Demand (MW)	Load Factor (%)
Jan-09	946,653	Mon Jan 26, 2009 8:00AM	1,678	1,272	75.8%
Feb-09	796,895	Tue Feb 10, 2009 8:00AM	1,429	1,186	83.0%
Mar-09	834,847	Wed Mar 11, 2009 8:00AM	1,585	1,122	70.8%
Apr-09	705,751	Wed Apr 1, 2009 11:00AM	1,295	980	75.7%
May-09	708,039	Fri May 29, 2009 4:00PM	1,258	952	75.7%
Jun-09	704,569	Thu Jun 4, 2009 6:00PM	1,286	979	76.1%
Jul-09	786,248	Mon Jul 27, 2009 5:00PM	1,502	1,057	70.4%
Aug-09	769,272	Mon Aug 3, 2009 5:00PM	1,522	1,034	67.9%
Sep-09	697,311	Wed Sep 2, 2009 5:00PM	1,451	968	66.8%
Oct-09	754,475	Mon Oct 12, 2009 8:00AM	1,332	1,014	76.1%
Nov-09	795,840	Mon Nov 30, 2009 6:00PM	1,400	1,105	79.0%
Dec-09	982,507	Tue Dec 8, 2009 7:00PM	1,763	1,321	74.9%
Annual	9,482,407	Tue Dec 8, 2009 7:00PM	1,763	1,082	61.4%

Table 9 – System Load Summary Statistics

Figure 3 shows these results graphically. Please note that the scale is *not* set at zero on the load factor plot so this graph exaggerates the variation from month to month.

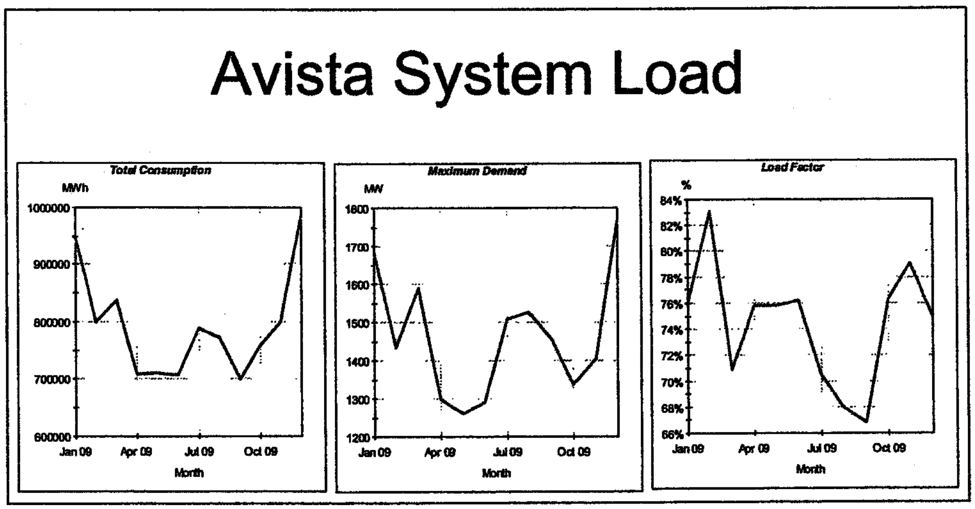


Figure 3 – Monthly Summary Statistics

Figure 4 shows the 24-hour profile of the total system load on the August and December peak days. The summer peak shows a gradually increasing load throughout the day with a late afternoon peak. The winter peak is slightly bi-modal with an early morning and late evening peak. The base winter load is nearly as high as the peak summer load.

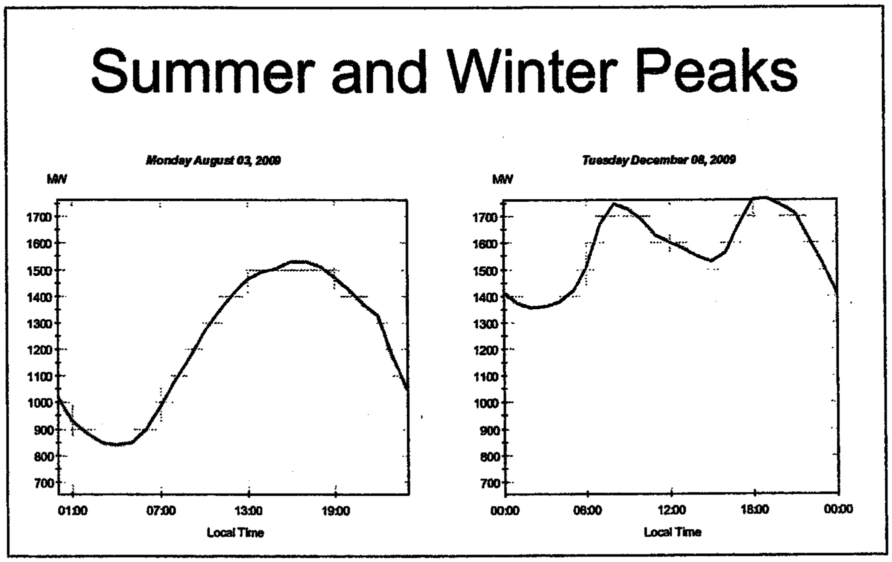


Figure 4 – System Summer and Winter Peaks

2.1.5 Annual kWh Sales by Rate Class

In this section, we will discuss information developed from the current billing data. Table 10 shows the number of accounts, total annual sales in kWh, and the average kWh sales per account in each rate class from the Avista "books and records." In addition, the table includes each rate schedule's contribution to the total load for each jurisdiction (Washington and Idaho) and each rate schedule's contribution to the overall total Avista system load.

Jurisdiction	Rate Schedule	Description	Number of Accounts	Total Annual Energy Use (kWh)	Average Annual Energy Use (kWh)	Percent of Jurisdictional Total	Percent of Avista Total
Washington	001	Residential	199,842	2,447,261,373	12,246	44.6%	27.4%
Washington	011/012	General Service	27,161	418,437,869	15,406	7.6%	4.7%
Washington	021/022	Large General Service	3,347	1,574,380,056	470,385	28.7%	17.7%
Washington	025	Extra Large General Service	22	889,056,291	40,411,650	16.2%	10.0%
Washington	031/032	Pumping	2,364	136,399,767	57,699	2.5%	1.5%
Washington	LGT	Street and Area Lights	-	26,610,041	-	0.5%	0.3%
		Washington Totals	232,736	5,492,145,397	23,598	100.0%	61.6%
Idaho	001	Residential	99,827	1,179,605,988	11,817	34.4%	13.2%
Idaho	011/012	General Service	19,288	321,565,148	16,672	9.4%	3.6%
Idaho	021/022	Large General Service	1,426	690,899,548	484,502	20.2%	7.7%
Idaho	25	Extra Large General Service	10	275,745,808	27,574,581	8.0%	3.1%
Idaho	25P	Extra Large General Service - CP	1	887,049,080	887,049,080	25.9%	9.9%
Idaho	031/032	Pumping	1,316	58,556,595	44,496	1.7%	0.7%
Idaho	LGT	Street and Area Lights	-	13,839,105	-	0.4%	0.2%
		Idaho Totals	121,868	3,427,261,272	28,123	100.0%	38.4%
		AVISTA Totals	354,604	8,919,406,669	25,153		100.0%

*Note: Street and area light customer counts are not included since lighting customers are counted in a different manner than the rest of the classes (i.e., contracts and/or number of lights), therefore the average annual energy use is not meaningful in this context.

Table 10 – "Books and Records" Population Counts and Consumption Data

2.1.6 Sample Design

For some customer classes, i.e., residential, small general service, large general service and pumping, it is not practical to collect load profile data for every customer within the class. For these classes, load study samples were designed with KEMA's assistance to be representative of Avista's customer classes throughout Avista's service territory (both Washington and Idaho) at a generally-accepted level of statistical precision (confidence that the demand estimates calculated using samples are within ten percent of the "true" population demand for a majority of hours). For these classes, customers were randomly selected to be part of a load study following a stratified sample design using the annual use of the customer as the primary stratification variable. After selection, Avista installed recording device on the statistically selected samples of customers, periodically collected data from the load recording devices, routinely conducted quality assurance, stored the data from the sample and transferred the data to KEMA for analysis. KEMA used the resultant data to conduct the load research expansion analysis (that is, estimate the population loads from the sample loads).

At the sample design phase, population billing data were provided to KEMA by Avista for use in constructing efficient sample designs for the following rate classes:

- Residential
- General Service
- Large General Service
- Public Pumping

The objective of sampling is to provide a statistically reliable estimate of the total demand in a particular class of customers. The analysis KEMA performed for Avista is grounded on the theory of Model Based Statistical Sampling (MBSS) which is discussed in more detail in the "Statistical Methodology" section of this report. Using the ratio model, stratified samples were constructed for each rate class and *expected* relative precisions were calculated.

State	Rate Code	Class	Error Ratio	Sample	Expected Relative Precision
Washington	001	Residential	0.900	168	± 11.60%
Idaho	001	Residential	0.900	82	± 16.69%
Total	001	Residential	0.900	250	± 9.52%
Washington	011/012	General Service	0.810	115	± 13.05%
Idaho	011/012	General Service	0.787	85	± 14.68%
Total	011/012	General Service	0.800	200	± 9.75%
Washington	021/022	Large General Service	0.498	52	± 11.47%
Idaho	021/022	Large General Service	0.505	23	± 17.56%
Total	021/022	Large General Service	0.500	75	± 9.61%
Washington	031/032	Pumping	0.985	50	± 23.72%
Idaho	031/032	Pumping	1.034	25	± 35.82%
Total	031/032	Pumping	1.000	75	± 19.78%

Table 11 – Sample Design Expected Relative Precision

The anticipated relative precisions for each of the samples at the time of the sample design are presented in Table 11, including the overall rate class precision, and the precision by rate class and jurisdiction. The Residential, General Service, and Large General Service classes overall were expected to achieve precision within ten percent, and the classes broken out by jurisdiction follow closely with slightly higher precision percentages (as expected given their smaller sample sizes). Higher relative precision percentages are common for irrigation or pumping customers given the high variability of customer loads within the class.

The results of this project were in line with the anticipated precisions presented above ensuring that the project has provided statistically reliable data for developing independent estimates for each class within each jurisdiction.

2.2 Analysis Approach

2.2.1 Overview of Class Load Profile Development

KEMA performed the following steps to conduct the analysis presented in this report:

1) Load profile data validation and estimation,
2) Identified the monthly system peak days, hours and collection of hours using the Avista system load data,
3) Post stratified the available hourly load data using the current billing data to calculate case weights for use in the expansion analysis,
4) Using the case weights expanded the 2009 load data to estimate the class load contributions for the various schedules of interest. The expansions yielded estimates of totals, means, error bounds for the totals, error bounds for the means, achieved relative precision and error ratios for each target variable of interest,
5) Applied loss factors provided by Avista to the load research class expansions,
6) The revised hourly expansions for each rate class were summed and compared to the actual system load (this results in a residual load known as unaccounted for energy[2], or "UFE", and
7) Finally, the UFE was applied to each rate class based on the proportion of the rate class's contribution to the individual hour yielding the reconciled class load.

Several classes had hourly data available for all the customers within the rate class, so the total class loads were simply calculated by adding together the individual customer loads. Rate classes with data available for all customers included the Extra Large

[2] Unaccounted for energy (UFE) refers to the difference between the total of the class estimates and the actual system load data which can result from sampling error. UFE is not referring to unaccounted for energy that results from theft or "lost" meters.

General Service (WA), Extra Large General Service (ID), and Extra Large General Service – CP (ID).

In addition, certain class loads were estimated using "deemed" profiles which provides an estimate or calculation of the total class load and is carried into the raw analysis without adjustment. That is, no post-stratification or expansion occurs for deemed profiles, as they are the total class load profile. Street and Area Lights class loads are deemed profiles in this analysis.

2.2.2 Verification and Editing of the Class Interval Data

One of the first tasks undertaken was to systematically and thoroughly examine each available interval load point for the schedules with load study sample data. The objective of the examination was to identify and correct anomalous points and missing data. Where appropriate, the acceptable data was used to derive an estimate for this data. The first step in this task was to review each site using *KEMA*'s proprietary Visualize-IT software program. The purpose of this examination was to identify anomalous data points, such as spikes, or changes in multipliers.

For example, Figure 5 shows the load shape for an individual site. For a brief number of intervals, this site exhibited a spike in demand 10 times larger than the typical demand. Accordingly, it was deemed anomalous, and eliminated from the individual customer profile. Figure 6 shows the same site with the anomalous data omitted.

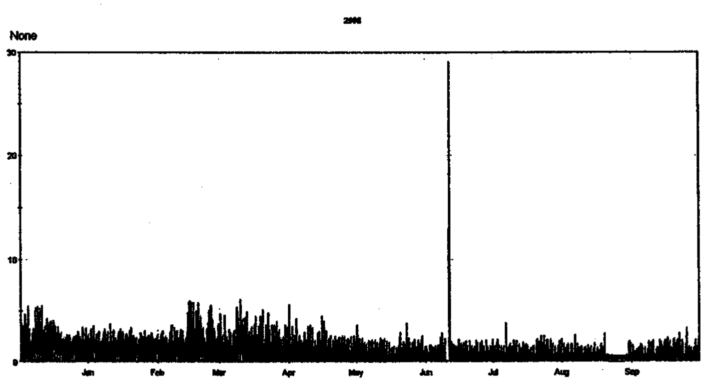


Figure 5 – Example of an Anomalous Spike

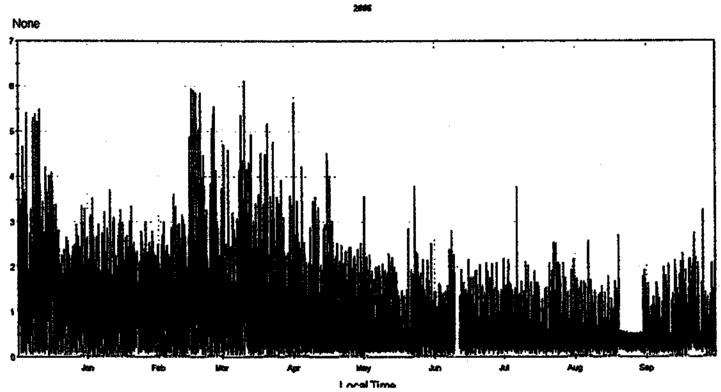


Figure 6 – Load Shape with the Spike Corrected

The second step was to correct the anomalies and fill in the missing intervals. For the classes that showed weather sensitive load we developed temperature response models for use in filling in the missing intervals. Using the valid, non missing data for a site, models were developed by day-of-week for each hour of the day. The development of the temperature demand models follow a seven-step procedure:

1. **Identify Holidays:** After reading in the hourly load data and checking for anomalous data, holidays are identified and reassigned. Since holidays tend to have a unique load pattern similar to a weekend these were reclassified as Sundays for this analysis. The holidays include New Years Day, Memorial Day, July 4th, Labor Day, Thanksgiving, and Christmas.
2. **Determine the Base Load:** The next step determines the base loads. The demands for each customer are calculated by day of the week and time of day. The median of the lowest five non-zero loads by day of the week and time are designated as the base load of the customer.
3. **Determine the Variable Load:** The third step determines the variable load. For each customer the base load is matched to the total load by day of the week and time. The variable load is calculated as the difference between the total load and the base load. If the variable load is less than zero, the variable load is set equal to zero.
4. **Merge Load Information with Temperature Data:** The next step matches the customer loads to the temperature file. Temperature data from the Spokane NOAA weather station was used.
5. **Initial Regression Analysis:** For each customer an initial regression analysis will be performed. Using the model shown below:

$$VL_{lrid,dow,time} = \beta_0 + \beta_1 * HDD + \beta_2 * CDD$$

Where:

$VL_{lrid,dow,time}$ is the Variable Load for customer 'LRID', on day of the week 'DOW' at hour ending 'Time'.

HDD are the heating degree-days (varying temperature base based on optimal customer response)

CDD are the cooling degree-days (varying temperature base based on optimal customer response)

The results of this model are used to identify outliers. Any observation with a studentized residual of greater than 3 will be trimmed from the analysis data set.

6. **Final Regression Analysis:** Using the analysis trimmed data set, the final regression analysis was performed. For each day of the week and hour of the day, a model is developed.

A family of models is examined for each customer by day of the week and time of day. These models include only cooling degree-days, models that include heating degree-days and models that include both heating and cooling degree-days.

To further optimize the selection of the models, a range of degree-day set points are considered for each test group model. For heating degree-days the considered set points will range from 500 to 700. For cooling degree-days the considered set points will range from 640 to 780. Mathematically, the models under consideration can be expressed as follows:

$$VL_{lrid,dow,time}=\beta_0 + \beta_1 * HDD(\tau_1) + \beta_2*CDD(\tau_2)$$

Where

$VL_{lrid,dow,time}$ is the same as above

$HDD(\tau_1)$ are the heating degree-days with a τ_1 base

$CDD(\tau_2)$ are the cooling degree-days with a τ_2 base

For each test group, for each day of the week for each hour 840 models are considered. The optimal model amongst the 840 alternatives is determined based on the minimization of the mean squared error of the residuals (MSE)[3]. Using this selection method, 168 optimal models are chosen for each customer.

[3] Alternative models, with different numbers of independent variables, introduce a challenge to choosing an optimal model. One approach would rely on the maximization of R^2 to indicate the optimal model. However, in building mathematical regression models, the R^2 statistic has a tendency to increase as the number of independent variables increases. Therefore, when comparing models with different numbers of regressors, the maximum R^2 criteria may not lead to choosing the optimal model between alternative models. To avoid this possibility, an alternative method to determine the optimal model was used, the minimization of the mean squared error of the residuals (MS_E). The MS_E accounts for the decrease in the degrees of freedom when an

7. **Prediction of Missing Data:** After the models are verified, demands for missing period are determined using the hourly temperature of the specific period.

For classes that appeared to have distinct patterns of consumption depending on time of day and day of week, we used data for similar hours for similar days of the week within season.

The third editing step was to reexamine each individual site using Visualize-IT. This examination compared the original and filled data for the site. Figure 7 shows an example of an original and filled load shape. As evidenced, the "corrected" profile provides a very good estimate of what the original profile was likely to have done during the missing data periods.

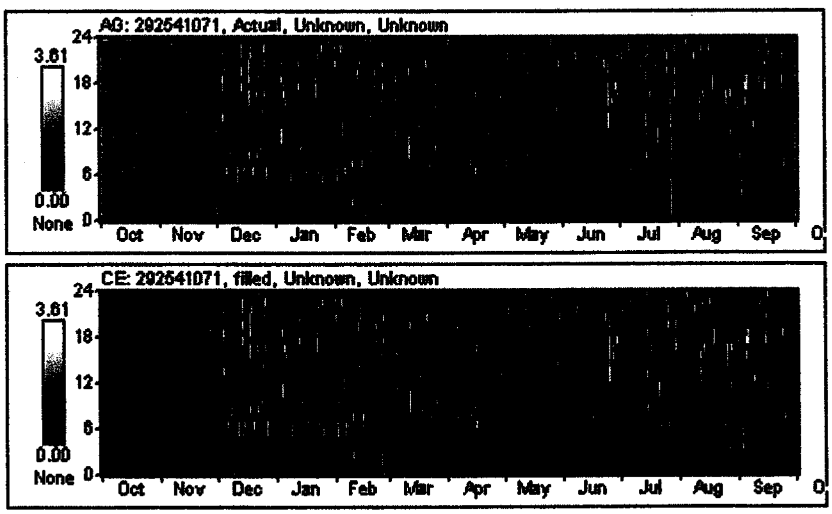


Figure 7 -- Comparison of Original and Filled Load Shape

Table 12 presents a recapitulation of the editing procedure. This table shows that there were over 5.4 million intervals examined. Of these, 5.2 million (97%) were accepted as valid. About 2.7% of the intervals were filled due to missing data or they were deemed anomalous and corrected. Only 0.87% of the intervals were left missing.

additional regressor is added to the equation. Therefore, the model that minimized the MS_E was chosen as the optimal model to represent the temperature versus demand relationship.

Jurisdiction	Rate Schedule	Description	Original Non-Missing Intervals Accepted	Original Intervals Kept Missing (Not Filled)	Intervals Filled	Total Intervals	Percent of Intervals Filled
Washington	001	Residential	1,527,562	0	22,958	1,550,520	1.5%
Washington	011/012	General Service	896,598	18,269	31,213	946,080	3.3%
Washington	021/022	Large General Service	438,491	0	8,269	446,760	1.9%
Washington	025	Extra Large General Service	181,745	0	2,215	183,960	1.2%
Washington	031/032	Pumping	356,313	15,329	22,558	394,200	5.7%
		Washington Totals	3,400,709	33,598	87,213	3,521,520	2.5%
Idaho	001	Residential	658,272	0	16,248	674,520	2.4%
Idaho	011/012	General Service	710,185	0	25,655	735,840	3.5%
Idaho	021/022	Large General Service	242,265	7,018	4,757	254,040	1.9%
Idaho	25	Extra Large General Service	64,097	0	5,983	70,080	8.5%
Idaho	25P	Extra Large General Service - CP	17,520	0	0	17,520	0.0%
Idaho	031/032	Pumping	197,518	6,988	5,734	210,240	2.7%
		Idaho Totals	1,889,857	14,006	58,377	1,962,240	3.0%
		AVISTA Totals	5,290,566	47,604	145,590	5,483,760	2.7%

Table 12 – Edit Procedure Summary Table

2.2.3 Statistical Methodology

This analysis is grounded on the theory of Model Based Statistical Sampling (MBSS). Most of the principles and methods of MBSS theory are discussed in Sarndal, Swensson and Wretman, *Model Assisted Survey Sampling* and Wright, *Methods and Tools of Load Research*. The methods are also taught in the AEIC's *Advanced Application of Load Research* seminar.

The objective of sampling is to provide a statistically reliable estimate of the total demand in a particular class of customers. The MBSS methodology improves the statistical precision by taking advantage of the correlation between the measure of demand of interest, called the target variable, and the auxiliary information available from the billing data. We usually use prior load data or general experience to estimate a model between a particular target variable *y*, e.g., the kW in an individual hour or the average kW in the 12 monthly system peak hours, and a supporting variable *x*, such as annual kWh, that is known in the population. Once the parameters of the model have been estimated, we can apply the model to the values of *x* in the population to assess the expected statistical precision for the target variable, and to develop efficiently stratified sample designs.

We assume the MBSS ratio model relating *y* to *x*. The primary equation of the model is:

$$y_i = \beta x_i + \varepsilon_i \qquad (1)$$

This is similar to a zero-intercept regression model, except that we assume that the standard deviation of the random term ε_i varies from one customer *i* to another, depending on the value of x_i, according to the secondary equation:

$$sd(\varepsilon_i \mid x_i) = sd(\varepsilon_i) = \sigma_0 (x_i)^{\gamma} \tag{2}$$

Here β , σ_0 and γ are parameters that are assumed to be constant from customer to customer in a given class of *N* customers labeled $i = 1, 2, \ldots, N$. We denote $\sigma_i = sd(\varepsilon_i)$ and $\mu_i = \beta x_i$.

Then we define the error ratio as:

$$er = \frac{\sum_{i=1}^{N} \sigma_i}{\sum_{i=1}^{N} \mu_i} \tag{3}$$

A model-based design suitable for stratified ratio or regression estimators can usually be developed from just two parameters: the error ratio, *er* and the parameter, γ, written as gamma.

The error ratio measures the total residual standard deviation in the population. Given the error ratio, the expected relative precision at the 90% level of confidence can be estimated using the following equation:

$$rp = 1.64\sqrt{1 - \frac{n}{N}}\frac{er}{\sqrt{n}} \tag{4}$$

Here *N* is the number of units in the population and *n* is the planned sample size. This assumes the use of an efficiently stratified sample design and a combined ratio estimator. Gamma, γ, characterizes the degree of heteroscedasticity in the secondary equation (2) and is used to develop the efficiently stratified sample design.

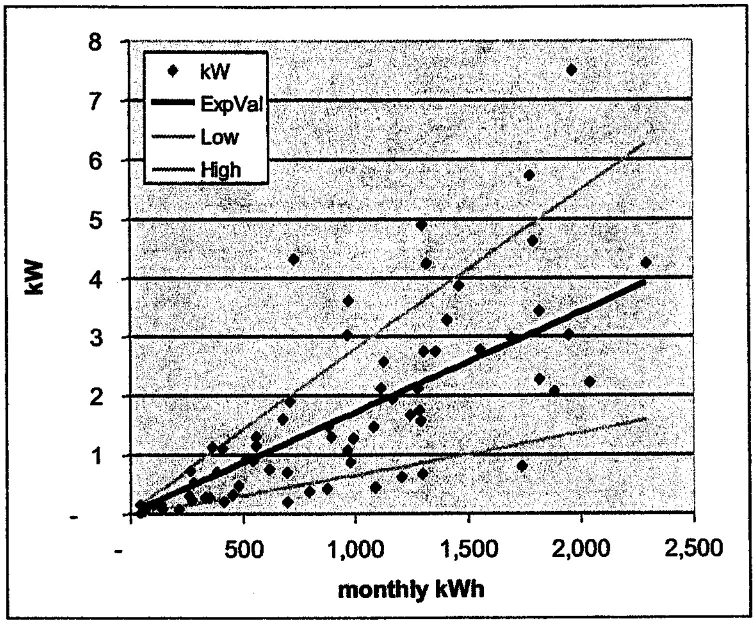


Figure 8 – The MBSS Model

Figure 8 illustrates these ideas. The figure shows a typical scatter plot of sample data. The variable (*x*) plotted on the horizontal axis is the average monthly kWh energy use of each sample customer, known from billing data. The variable (*y*) plotted on the vertical axis is the customer's kW demand coincident with the hour of the system peak. The dark trend line is the expected demand of each customer as a function of the monthly kWh of the customer. The lighter lines are the expected demand plus and minus one standard deviation. These three lines reflect the parameters of the estimated model. The key parameter is the error ratio, which in this case is 0.63. This indicates that one standard deviation is equal to about 0.63 times the expected value of demand for this population in this hour. In this particular case, gamma was found to be approximately equal to one, but 0.8 is more typical and can be used in most applications.

We used the following data to inform our MBSS analysis:

- Hourly load data for each sample customer in the current load study for each of the rate classes and domains of interest,
- System load data for the 12-month period ending December 31, 2009, and
- Current billing data for each customer in each class, especially annual kWh consumption.

2.3 Class Load Profiles - Washington State

The following sections present the results of the reconciled class load for each of the rate classes in Washington State.

2.3.1 Residential (WA)

The sample data was expanded by post-stratifying the Residential (WA) class. Table 13 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use[4] in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample. Please note that these statistics vary slightly from Table 10 due to slight timing differences between data in the population billing file and those used as the accounting "books and records." The data in Table 13 was used to construct appropriate weights, whereas the data in Table 10 was used in the preliminary expansion analysis.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
WA	1	Residential	1	8,769	417,294,539	71,878	41	1,753.1
WA	1	Residential	2	12,067	462,415,795	44,628	37	1,206.2
WA	1	Residential	3	15,861	489,635,562	35,486	39	909.9
WA	1	Residential	4	21,651	518,456,857	28,256	28	1,009.1
WA	1	Residential	5	229,940	568,442,333	20,019	32	625.6
Class Totals					2,456,245,085	200,267	177	

Table 13 – Residential (WA) Post-Stratification

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular

[4] There were a handful of accounts with extreme usage values associated with them. Their inclusion will not materially affect the results of the analysis.

hour. The residential class in Washington represents approximately 33% of the total system load and therefore received about one-third of the UFE[5].

Figure 9 presents the results of the reconciled hourly expansion analysis for the Residential (WA) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The dominance of the winter load is clearly evident with bi-modal peaks occurring in the morning and early evening periods. The Residential (WA) class peaks on Tuesday, December 8, 2009 at 7 PM. The peak demand was 710 MW.

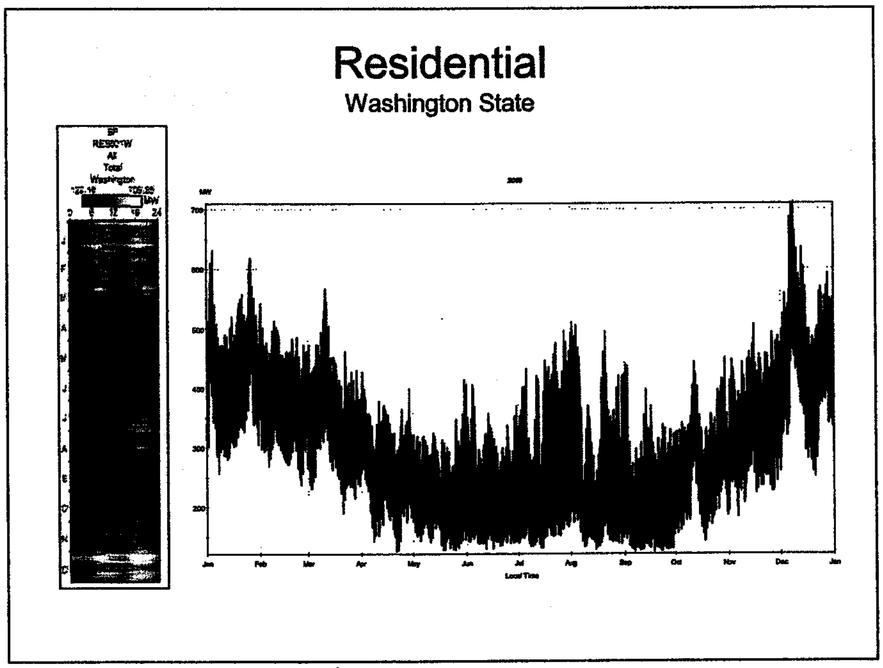


Figure 9 – Residential (WA) Class Load

[5] The UFE varied on an interval by interval basis.

Figure 10 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The winter bi-modal peak is clearly evident in the weekday and peak day profiles. The weekend profiles display a similar level of magnitude with a slightly higher load factor (i.e., flatter load shape) when compared to the weekday profiles.

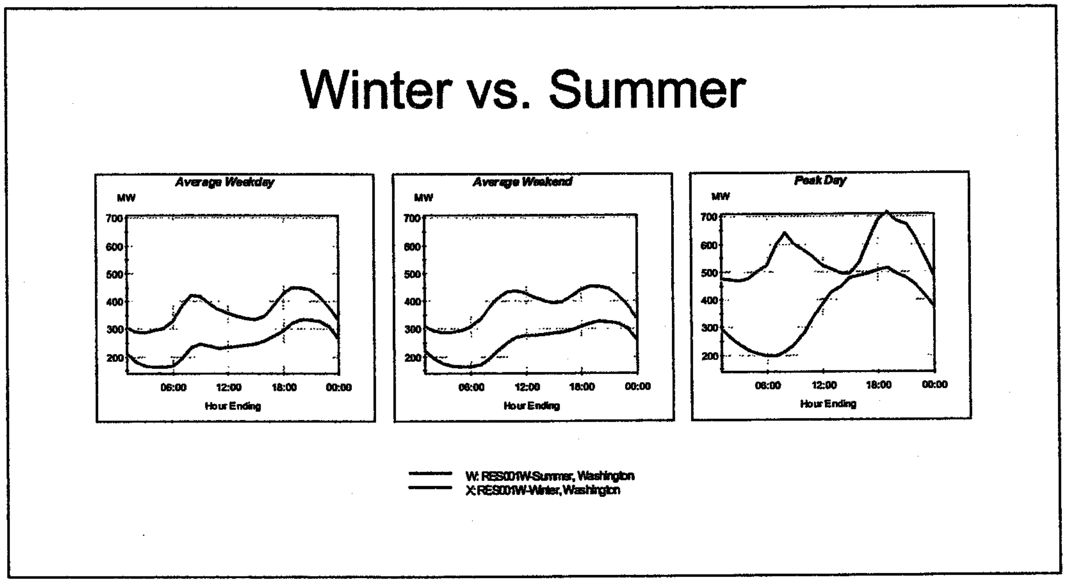


Figure 10 – Residential (WA) Winter vs. Summer

Figure 11 presents a summary of the achieved relative precision[6] associated with the Residential (WA) class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. For example, 65% of all hours are at or below a precision of ±10%. The majority of hours (i.e., 95% of all hours) were at or below ±11.9%.

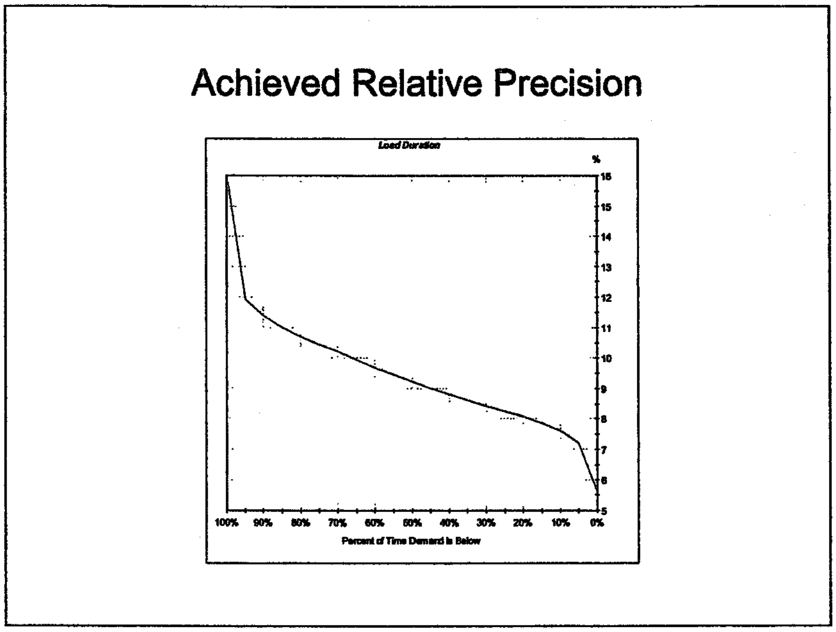


Figure 11 – Residential (WA) Achieved Relative Precision

Table 14 presents summary statistics for the Residential (WA) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[6] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 50% in August and September to a high of 69% in February. The Residential (WA) class load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for 11 of the 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	308,337	Sun Jan 4, 2009 7:00PM	629	414	66%	Mon Jan 26, 2009 8:00AM	607	97%
Feb-09	249,433	Sun Feb 1, 2009 11:00AM	540	371	69%	Tue Feb 10, 2009 8:00AM	478	89%
Mar-09	251,920	Wed Mar 11, 2009 9:00AM	565	339	60%	Wed Mar 11, 2009 9:00AM	565	100%
Apr-09	184,101	Wed Apr 1, 2009 9:00PM	425	256	60%	Wed Apr 1, 2009 12:00PM	359	85%
May-09	166,560	Sat May 30, 2009 7:00PM	412	224	54%	Fri May 29, 2009 5:00PM	293	71%
Jun-09	161,445	Thu Jun 4, 2009 8:00PM	403	224	56%	Thu Jun 4, 2009 7:00PM	380	94%
Jul-09	195,859	Mon Jul 27, 2009 7:00PM	494	263	53%	Mon Jul 27, 2009 6:00PM	455	92%
Aug-09	187,439	Sat Aug 1, 2009 7:00PM	509	252	50%	Mon Aug 3, 2009 6:00PM	450	88%
Sep-09	156,475	Tue Sep 1, 2009 7:00PM	437	217	50%	Wed Sep 2, 2009 6:00PM	404	92%
Oct-09	199,612	Thu Oct 29, 2009 8:00PM	448	268	60%	Mon Oct 12, 2009 9:00AM	408	91%
Nov-09	238,520	Sun Nov 15, 2009 6:00PM	504	331	66%	Mon Nov 30, 2009 6:00PM	455	90%
Dec-09	332,019	Tue Dec 8, 2009 7:00PM	710	446	63%	Tue Dec 8, 2009 7:00PM	710	100%
Annual	2,631,721	Annual Class Peak	710	300	42%	Annual System Peak	710	100%

Table 14 – Residential (WA) Summary Statistics (Totals – MW)

Table 15 presents the same information as Table 14 but on a per-account basis. The average Residential (WA) customer uses 13,150 kWh with an average demand of 3.6 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	1,541	Sun Jan 4, 2009 7:00PM	3.1	2.1	66%	Mon Jan 26, 2009 8:00AM	3.0	96%
Feb-09	1,246	Sun Feb 1, 2009 11:00AM	2.7	1.9	69%	Tue Feb 10, 2009 8:00AM	2.4	89%
Mar-09	1,259	Wed Mar 11, 2009 9:00AM	2.8	1.7	60%	Wed Mar 11, 2009 9:00AM	2.8	100%
Apr-09	920	Wed Apr 1, 2009 9:00PM	2.1	1.3	60%	Wed Apr 1, 2009 12:00PM	1.8	84%
May-09	832	Sat May 30, 2009 7:00PM	2.1	1.1	54%	Fri May 29, 2009 5:00PM	1.5	71%
Jun-09	807	Thu Jun 4, 2009 8:00PM	2.0	1.1	56%	Thu Jun 4, 2009 7:00PM	1.9	95%
Jul-09	979	Mon Jul 27, 2009 7:00PM	2.5	1.3	53%	Mon Jul 27, 2009 6:00PM	2.3	92%
Aug-09	937	Sat Aug 1, 2009 7:00PM	2.5	1.3	50%	Mon Aug 3, 2009 6:00PM	2.3	89%
Sep-09	782	Tue Sep 1, 2009 7:00PM	2.2	1.1	50%	Wed Sep 2, 2009 6:00PM	2.0	92%
Oct-09	997	Thu Oct 29, 2009 8:00PM	2.2	1.3	60%	Mon Oct 12, 2009 9:00AM	2.0	91%
Nov-09	1,192	Sun Nov 15, 2009 6:00PM	2.5	1.7	66%	Mon Nov 30, 2009 6:00PM	2.3	90%
Dec-09	1,659	Tue Dec 8, 2009 7:00PM	3.6	2.2	63%	Tue Dec 8, 2009 7:00PM	3.6	100%
Annual	13,150	Annual Class Peak	3.6	1.5	42%	Annual System Peak	3.6	100%

Table 15 – Residential (WA) Summary Statistics (Means – kW)

2.3.2 General Service

The sample data was expanded by post-stratifying the General Service (WA) rate class. Table 16 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
WA	11	General Service	1	8,672	40,102,807	12,684	19	667.6
WA	11	General Service	2	16,870	50,147,476	4,068	15	271.2
WA	11	General Service	3	27,954	56,014,739	2,599	13	199.9
WA	11	General Service	4	46,121	61,937,548	1,738	14	124.1
WA	11	General Service	5	116,720	69,467,359	1,111	15	74.1
Schedule 11 Total					277,669,929	22,200	76	
WA	12	General Service	1	34,554	22,517,332	1,333	6	222.2
WA	12	General Service	2	49,535	26,121,794	616	4	154.0
WA	12	General Service	3	64,796	27,707,369	486	4	121.5
WA	12	General Service	4	79,466	29,067,085	404	7	57.7
WA	12	General Service	5	504,364	30,976,908	323	8	40.4
Schedule 12 Total					136,390,489	3,162	29	
Class Totals					414,060,418	25,362	105	

Table 16 – General Service (WA) Post-Stratification

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 12 presents the results of the reconciled hourly expansion analysis for the General Service (WA) class in Washington State. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. Daytimes loads are consistent throughout the year with a higher load factor during the winter months. The General Service (WA) class peaks on Monday, August 3, 2009 at 4 PM. The class peak demand was 97 MW.

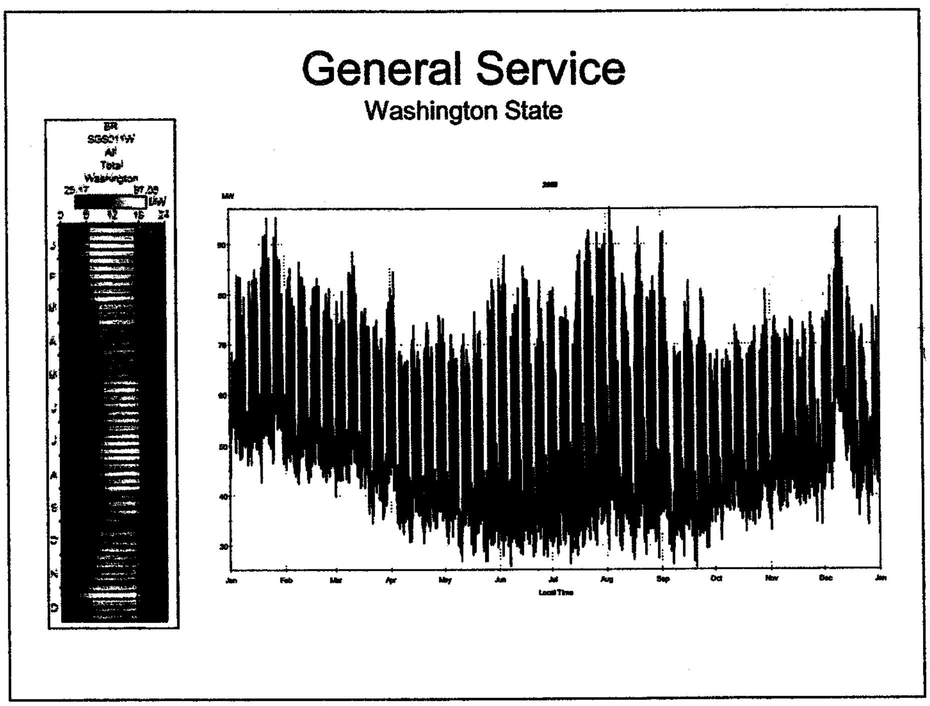


Figure 12 – General Service (WA) Class Load

Figure 13 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The winter and summer load shapes are similar with summer peaks occurring later in the day. The winter and summer weekend profiles display a lower and flatter load shape when compared to the weekday profiles with winter weekend loads lower than summer.

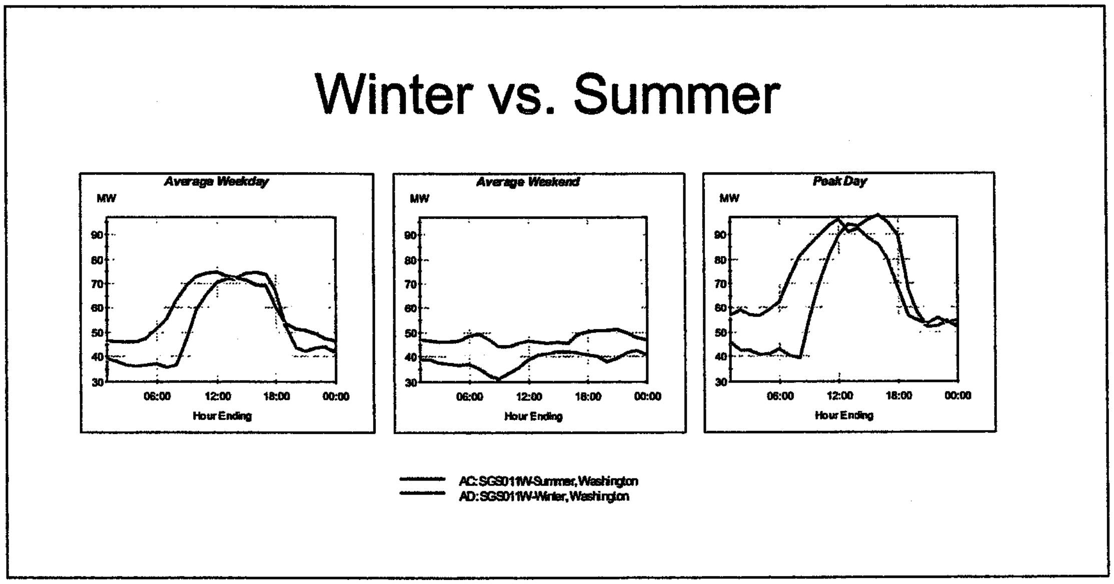


Figure 13 – General Service (WA) Winter vs. Summer

Figure 14 presents a summary of the achieved relative precision[7] associated with the General Service (WA) class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. For example, 75% of all hours are at or below a precision of ±12.8%. The majority of hours (i.e., 95% of all hours) were at or below ±15.6%.

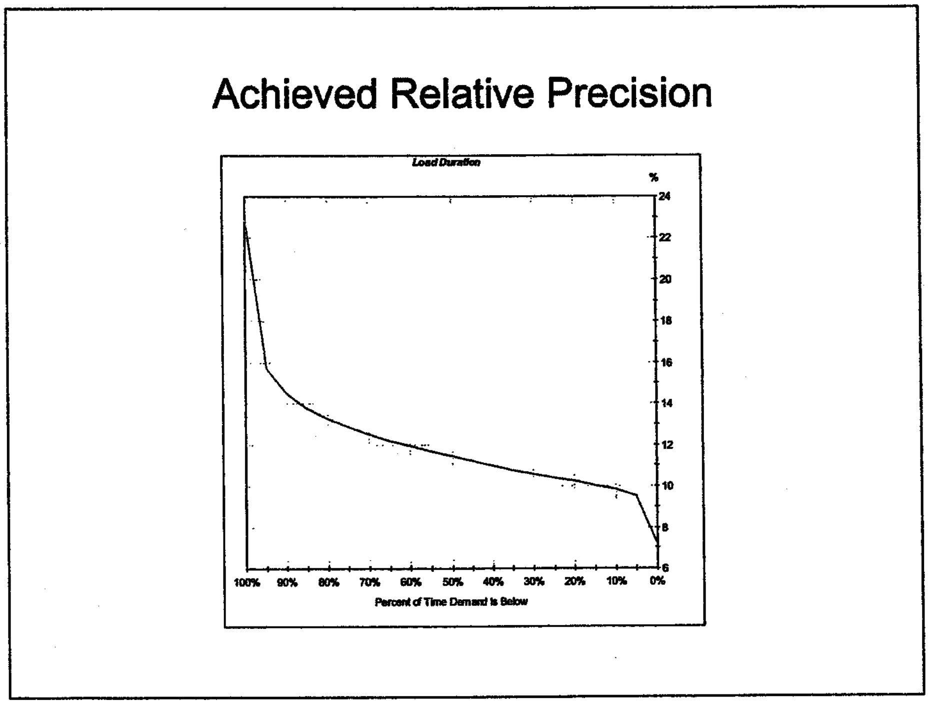


Figure 14 – General Service (WA) Achieved Relative Precision

Table 17 presents summary statistics for the General Service (WA) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[7] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 50% in September to a high of 67% in February and November. The General Service (WA) class load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for ten of the 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	45,636	Tue Jan 27, 2009 12:00PM	95	61	65%	Mon Jan 26, 2009 8:00AM	82	86%
Feb-09	38,419	Mon Feb 9, 2009 11:00AM	86	57	67%	Tue Feb 10, 2009 8:00AM	71	83%
Mar-09	39,665	Wed Mar 11, 2009 12:00PM	88	53	61%	Wed Mar 11, 2009 9:00AM	76	86%
Apr-09	33,868	Fri Apr 3, 2009 1:00PM	84	47	56%	Wed Apr 1, 2009 12:00PM	81	96%
May-09	33,057	Thu May 28, 2009 5:00PM	83	44	54%	Fri May 29, 2009 5:00PM	79	96%
Jun-09	33,965	Thu Jun 4, 2009 4:00PM	87	47	54%	Thu Jun 4, 2009 7:00PM	62	71%
Jul-09	37,298	Wed Jul 22, 2009 4:00PM	92	50	54%	Mon Jul 27, 2009 6:00PM	90	98%
Aug-09	36,640	Mon Aug 3, 2009 4:00PM	97	49	51%	Mon Aug 3, 2009 6:00PM	89	92%
Sep-09	32,817	Wed Sep 2, 2009 4:00PM	92	46	50%	Wed Sep 2, 2009 6:00PM	82	89%
Oct-09	35,801	Thu Oct 29, 2009 12:00PM	81	48	60%	Mon Oct 12, 2009 9:00AM	68	85%
Nov-09	36,545	Mon Nov 23, 2009 5:00PM	76	51	67%	Mon Nov 30, 2009 6:00PM	61	80%
Dec-09	42,502	Thu Dec 10, 2009 12:00PM	95	57	60%	Tue Dec 8, 2009 7:00PM	64	67%
Annual	446,214	Annual Class Peak	97	51	52%	Annual System Peak	64	66%

Table 17 – General Service (WA) Summary Statistics (Totals – MW)

Table 18 presents the same information as Table 17 but on a per-account basis. The average General Service (WA) customer uses 16,440 kWh with an average demand of 3.6 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	1,681	Tue Jan 27, 2009 12:00PM	3.5	2.3	65%	Mon Jan 26, 2009 8:00AM	3.0	86%
Feb-09	1,416	Mon Feb 9, 2009 11:00AM	3.2	2.1	67%	Tue Feb 10, 2009 8:00AM	2.6	83%
Mar-09	1,461	Wed Mar 11, 2009 12:00PM	3.3	2.0	61%	Wed Mar 11, 2009 9:00AM	2.8	86%
Apr-09	1,248	Fri Apr 3, 2009 1:00PM	3.1	1.7	56%	Wed Apr 1, 2009 12:00PM	3.0	96%
May-09	1,218	Thu May 28, 2009 5:00PM	3.0	1.6	54%	Fri May 29, 2009 5:00PM	2.9	96%
Jun-09	1,251	Thu Jun 4, 2009 4:00PM	3.2	1.7	54%	Thu Jun 4, 2009 7:00PM	2.3	70%
Jul-09	1,374	Wed Jul 22, 2009 4:00PM	3.4	1.9	54%	Mon Jul 27, 2009 6:00PM	3.3	98%
Aug-09	1,350	Mon Aug 3, 2009 4:00PM	3.6	1.8	51%	Mon Aug 3, 2009 6:00PM	3.3	91%
Sep-09	1,209	Wed Sep 2, 2009 4:00PM	3.4	1.7	50%	Wed Sep 2, 2009 6:00PM	3.0	89%
Oct-09	1,319	Thu Oct 29, 2009 12:00PM	3.0	1.8	60%	Mon Oct 12, 2009 9:00AM	2.5	85%
Nov-09	1,346	Mon Nov 23, 2009 5:00PM	2.8	1.9	67%	Mon Nov 30, 2009 6:00PM	2.2	80%
Dec-09	1,566	Thu Dec 10, 2009 12:00PM	3.5	2.1	60%	Tue Dec 8, 2009 7:00PM	2.4	67%
Annual	16,440	Annual Class Peak	3.6	1.9	52%	Annual System Peak	2.4	66%

Table 18 – General Service (WA) Summary Statistics (Means – kW)

2.3.3 Large General Service

The sample data was expanded by post-stratifying the Large General Service (WA) rate class. Table 19 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
WA	21	Large General Service	1	198,304	204,120,976	1,591	9	176.8
WA	21	Large General Service	2	394,922	237,591,246	860	13	66.2
WA	21	Large General Service	3	864,930	273,920,504	488	9	54.2
WA	21	Large General Service	4	2,173,940	325,204,764	244	9	27.1
WA	21	Large General Service	5	8,062,088	396,804,097	117	11	10.6
WA	21	Large General Service-Primary	6	16,109,066	127,395,037	35	1	35.0
Class Totals					1,565,036,623	3,335	52	

Table 19 – Large General Service (WA) Post-Stratification

In the second stage of the analysis, loss factors of 1.079 and 1.054 (provided by Avista) were applied to the hourly Large General Service (WA) and Large General Service-Primary (WA) rate class expansions, respectively.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 15 presents the results of the reconciled hourly expansion analysis for the Large General Service (WA) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum.

The summer load tends to be higher than the winter load. The Large General Service (WA) class peaks on Wednesday, September 16, 2009 at 4 PM. The peak demand was just under 324 MW.

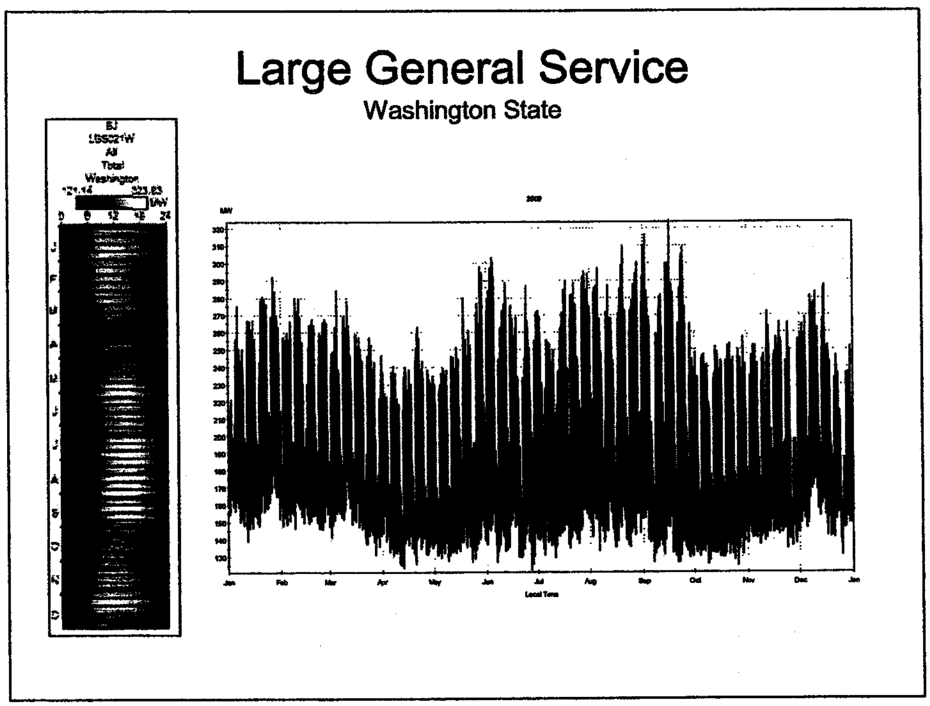


Figure 15 – Large General Service (WA) Class Load

Figure 16 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The winter and summer load shapes are very similar in both magnitude and shape. The weekend profiles are substantially lower than their weekday counterparts.

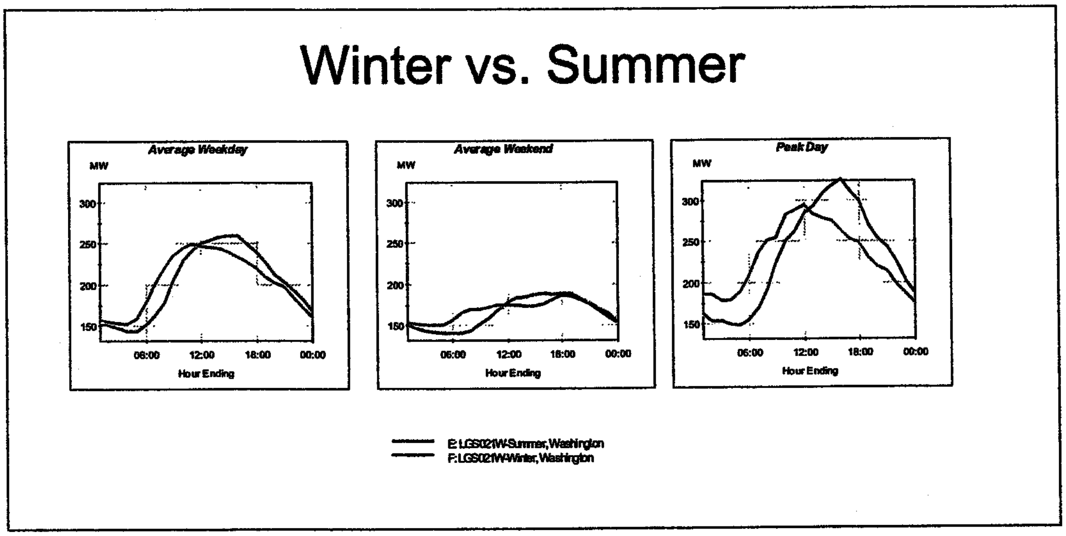


Figure 16 – Large General Service (WA) Winter vs. Summer

Figure 17 presents a summary of the achieved relative precision[8] associated with the Large General Service (WA) class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. For example, 60% of all hours are at or below a precision of ±10%. The majority of hours (i.e., 95% of all hours) were at or below ±12.4%.

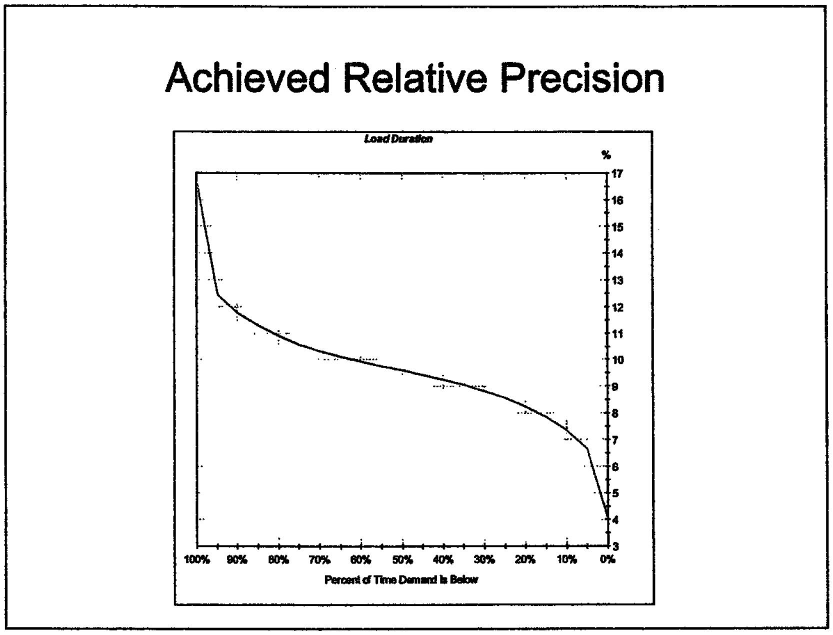


Figure 17 – Large General Service (WA) Achieved Relative Precision

Table 20 presents summary statistics for the Large General Service (WA) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[8] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 60% in September to a high of 71% in February. The Large General Service (WA) class load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for all 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	148,998	Tue Jan 27, 2009 12:00PM	291	200	69%	Mon Jan 26, 2009 8:00AM	249	85%
Feb-09	132,324	Mon Feb 9, 2009 10:00AM	279	197	71%	Tue Feb 10, 2009 8:00AM	242	87%
Mar-09	140,758	Thu Mar 5, 2009 11:00AM	284	189	67%	Wed Mar 11, 2009 9:00AM	247	87%
Apr-09	126,590	Tue Apr 21, 2009 3:00PM	262	176	67%	Wed Apr 1, 2009 12:00PM	232	89%
May-09	134,243	Thu May 28, 2009 2:00PM	297	180	61%	Fri May 29, 2009 5:00PM	288	97%
Jun-09	136,995	Thu Jun 4, 2009 4:00PM	302	190	63%	Thu Jun 4, 2009 7:00PM	241	80%
Jul-09	147,965	Tue Jul 28, 2009 5:00PM	295	199	68%	Mon Jul 27, 2009 6:00PM	288	98%
Aug-09	148,700	Thu Aug 20, 2009 2:00PM	308	200	65%	Mon Aug 3, 2009 6:00PM	276	89%
Sep-09	140,810	Wed Sep 16, 2009 4:00PM	324	196	60%	Wed Sep 2, 2009 6:00PM	301	93%
Oct-09	133,235	Thu Oct 29, 2009 12:00PM	256	179	70%	Mon Oct 12, 2009 9:00AM	213	83%
Nov-09	132,863	Thu Nov 12, 2009 11:00AM	271	184	68%	Mon Nov 30, 2009 6:00PM	221	82%
Dec-09	144,560	Tue Dec 15, 2009 12:00PM	286	194	68%	Tue Dec 8, 2009 7:00PM	232	81%
Annual	1,668,040	Annual Class Peak	324	190	59%	Annual System Peak	232	72%

Table 20 – Large General Service (WA) Summary Statistics (Totals – MW)

Table 21 presents the same information as Table 20 but on a per-account basis. The average Large General Service (WA) customer uses 497,700 kWh with an average demand of 96.6 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	44,457	Tue Jan 27, 2009 12:00PM	86.9	59.8	69%	Mon Jan 26, 2009 8:00AM	74.2	85%
Feb-09	39,482	Mon Feb 9, 2009 10:00AM	83.3	58.8	71%	Tue Feb 10, 2009 8:00AM	72.1	87%
Mar-09	41,999	Thu Mar 5, 2009 11:00AM	84.6	56.5	67%	Wed Mar 11, 2009 9:00AM	73.6	87%
Apr-09	37,771	Tue Apr 21, 2009 3:00PM	78.2	52.5	67%	Wed Apr 1, 2009 12:00PM	69.3	89%
May-09	40,055	Thu May 28, 2009 2:00PM	88.7	53.8	61%	Fri May 29, 2009 5:00PM	86.1	97%
Jun-09	40,876	Thu Jun 4, 2009 4:00PM	90.2	56.8	63%	Thu Jun 4, 2009 7:00PM	72.0	80%
Jul-09	44,149	Tue Jul 28, 2009 5:00PM	87.9	59.3	68%	Mon Jul 27, 2009 6:00PM	86.0	98%
Aug-09	44,368	Thu Aug 20, 2009 2:00PM	92.0	59.6	65%	Mon Aug 3, 2009 6:00PM	82.2	89%
Sep-09	42,014	Wed Sep 16, 2009 4:00PM	96.6	58.4	60%	Wed Sep 2, 2009 6:00PM	89.9	93%
Oct-09	39,754	Thu Oct 29, 2009 12:00PM	76.5	53.4	70%	Mon Oct 12, 2009 9:00AM	63.7	83%
Nov-09	39,643	Thu Nov 12, 2009 11:00AM	80.9	55.0	68%	Mon Nov 30, 2009 6:00PM	66.0	82%
Dec-09	43,133	Tue Dec 15, 2009 12:00PM	85.4	58.0	68%	Tue Dec 8, 2009 7:00PM	69.3	81%
Annual	497,700	Annual Class Peak	96.6	56.8	59%	Annual System Peak	69.3	72%

Table 21 – Large General Service (WA) Summary Statistics (Means – kW)

2.3.4 Extra Large General Service

Data for all customers in the Extra Large General Service (WA) were available, so the population count and sample size are the same, and each site's case weight is one.

In the second stage of the analysis, loss factors of 1.05675 and 1.038 (provided by Avista) were applied to the hourly Extra Large General Service and Extra Large General Service (IEP) loads, respectively.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 18 presents the results of the reconciled hourly expansion analysis for the Extra Large General Service (WA) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The Extra Large General Service (WA) class peaks on Tuesday, December 8, 2009 at noon. The peak demand was 146 MW.

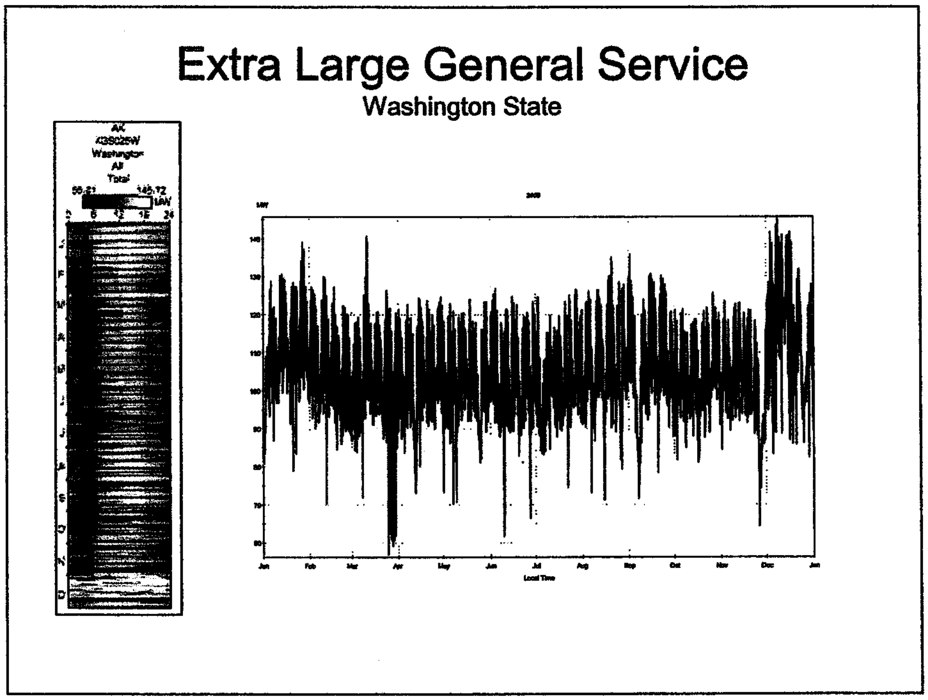


Figure 18 – Extra Large General Service (WA) Class Load

Figure 19 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The Extra Large General Service (WA) class displays similar average weekday and weekend profiles by season with the winter load slightly higher than the summer load. The peak day is quite distinct when compared to the average weekday or weekend day.

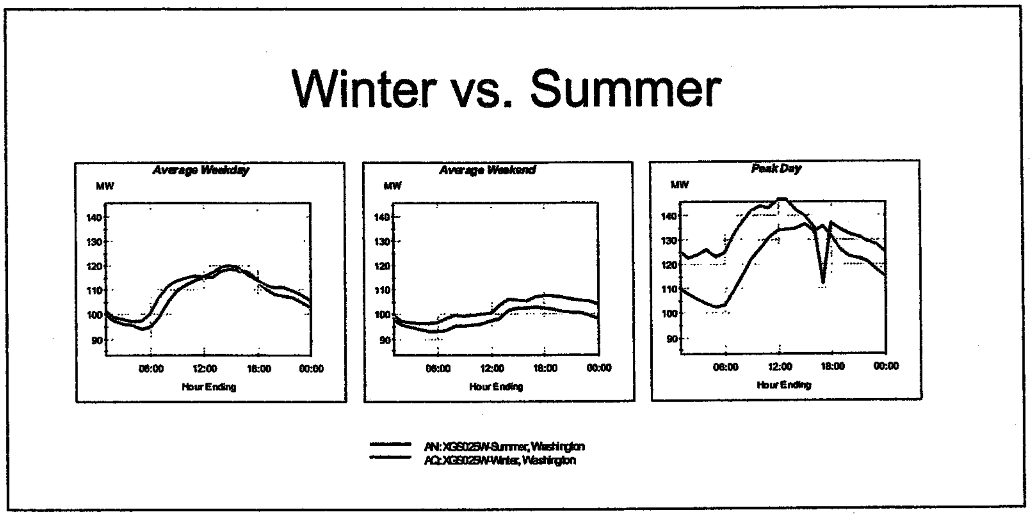


Figure 19 – Extra Large General Service (WA) Winter vs. Summer

The relative precision was perfect since the data for all of the customers in the class were available for the full 12 month period examined.

Table 22 presents summary statistics for the Extra Large General Service (WA) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

Monthly load factors ranged from a low of 72% in March to a high of 83% in April, May and October. The Extra Large General Service (WA) load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for all 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	82,427	Tue Jan 27, 2009 1:00PM	139	111	80%	Mon Jan 26, 2009 8:00AM	122	88%
Feb-09	71,581	Tue Feb 10, 2009 3:00PM	130	107	82%	Tue Feb 10, 2009 8:00AM	116	90%
Mar-09	75,413	Wed Mar 11, 2009 2:00PM	140	102	72%	Wed Mar 11, 2009 9:00AM	118	84%
Apr-09	74,683	Wed Apr 29, 2009 3:00PM	124	104	83%	Wed Apr 1, 2009 12:00PM	111	90%
May-09	76,252	Mon May 18, 2009 2:00PM	124	102	83%	Fri May 29, 2009 5:00PM	118	96%
Jun-09	74,555	Thu Jun 4, 2009 3:00PM	126	104	82%	Thu Jun 4, 2009 7:00PM	114	90%
Jul-09	76,263	Mon Jul 27, 2009 2:00PM	126	103	81%	Mon Jul 27, 2009 6:00PM	123	97%
Aug-09	78,825	Thu Aug 20, 2009 2:00PM	135	106	79%	Mon Aug 3, 2009 6:00PM	121	90%
Sep-09	76,521	Tue Sep 1, 2009 3:00PM	136	106	78%	Wed Sep 2, 2009 6:00PM	123	91%
Oct-09	77,438	Mon Oct 26, 2009 2:00PM	125	104	83%	Mon Oct 12, 2009 9:00AM	113	90%
Nov-09	73,229	Tue Nov 3, 2009 10:00AM	123	102	82%	Mon Nov 30, 2009 6:00PM	114	92%
Dec-09	86,032	Tue Dec 8, 2009 12:00PM	146	116	79%	Tue Dec 8, 2009 7:00PM	134	92%
Annual	923,220	Annual Class Peak	146	105	72%	Annual System Peak	134	92%

Table 22 – Extra Large General Service (WA) Summary Statistics (Totals – MW)

Table 23 presents the same information as Table 22 but on a per-account basis. The average Extra Large General Service (WA) customer uses 41,964,560 kWh with an average demand of 6,624 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	3,746,700	Tue Jan 27, 2009 1:00PM	6,305	5,036	80%	Mon Jan 26, 2009 8:00AM	5,555	88%
Feb-09	3,253,698	Tue Feb 10, 2009 3:00PM	5,893	4,842	82%	Tue Feb 10, 2009 8:00AM	5,279	90%
Mar-09	3,427,883	Wed Mar 11, 2009 2:00PM	6,374	4,614	72%	Wed Mar 11, 2009 9:00AM	5,382	84%
Apr-09	3,394,683	Wed Apr 29, 2009 3:00PM	5,647	4,715	83%	Wed Apr 1, 2009 12:00PM	5,067	90%
May-09	3,465,994	Mon May 18, 2009 2:00PM	5,625	4,659	83%	Fri May 29, 2009 5:00PM	5,381	96%
Jun-09	3,388,871	Thu Jun 4, 2009 3:00PM	5,747	4,707	82%	Thu Jun 4, 2009 7:00PM	5,175	90%
Jul-09	3,466,487	Mon Jul 27, 2009 2:00PM	5,740	4,659	81%	Mon Jul 27, 2009 6:00PM	5,571	97%
Aug-09	3,582,954	Thu Aug 20, 2009 2:00PM	6,123	4,816	79%	Mon Aug 3, 2009 6:00PM	5,499	90%
Sep-09	3,478,222	Tue Sep 1, 2009 3:00PM	6,164	4,831	78%	Wed Sep 2, 2009 6:00PM	5,604	91%
Oct-09	3,519,924	Mon Oct 26, 2009 2:00PM	5,695	4,731	83%	Mon Oct 12, 2009 9:00AM	5,150	90%
Nov-09	3,328,608	Tue Nov 3, 2009 10:00AM	5,597	4,617	82%	Mon Nov 30, 2009 6:00PM	5,166	92%
Dec-09	3,910,535	Tue Dec 8, 2009 12:00PM	6,624	5,256	79%	Tue Dec 8, 2009 7:00PM	6,077	92%
Annual	41,964,560	Annual Class Peak	6,624	4,790	72%	Annual System Peak	6,077	92%

Table 23 – Extra Large General Service (WA) Summary Statistics (Means – kW)

2.3.5 Pumping

The sample data was expanded by post-stratifying the Pumping (WA) rate class. Table 24 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
WA	31	Pumping Service	1	47,687	15,415,874	1,631	8	203.9
WA	31	Pumping Service	2	123,131	21,060,758	280	10	28.0
WA	31	Pumping Service	3	381,547	25,966,498	121	9	13.4
WA	31	Pumping Service	4	1,183,935	31,624,846	49	7	7.0
WA	31	Pumping Service	5	5,110,715	42,589,679	21	8	2.6
Class Totals					136,657,655	2,102	42	

Table 24 – Pumping (WA) Post-Stratification

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 20 presents the results of the reconciled hourly expansion analysis for the Pumping (WA) rate class in Washington State. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The dominance of the summer load is clearly evident with only minimal load in the winter months. The Pumping (WA) class peaks on Friday, June 5, 2009 at 6 PM. The peak demand was about 49 MW.

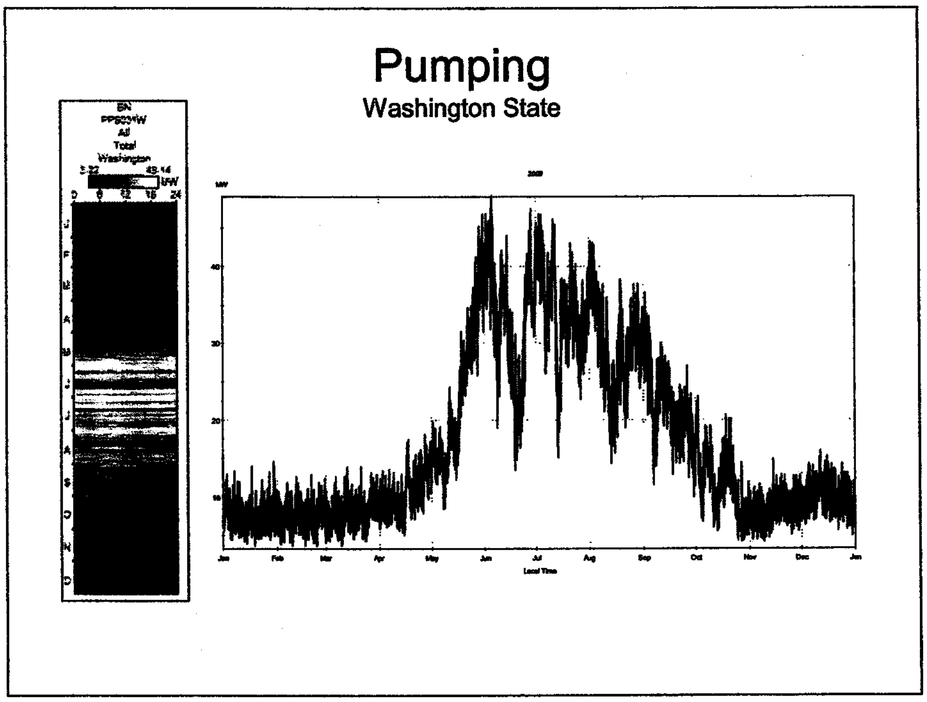


Figure 20 – Pumping (WA) Class Load

Figure 21 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The pumping load is highest during the summer period. The average weekday and weekend load shapes are very similar by season and differ dramatically from the class peak load.

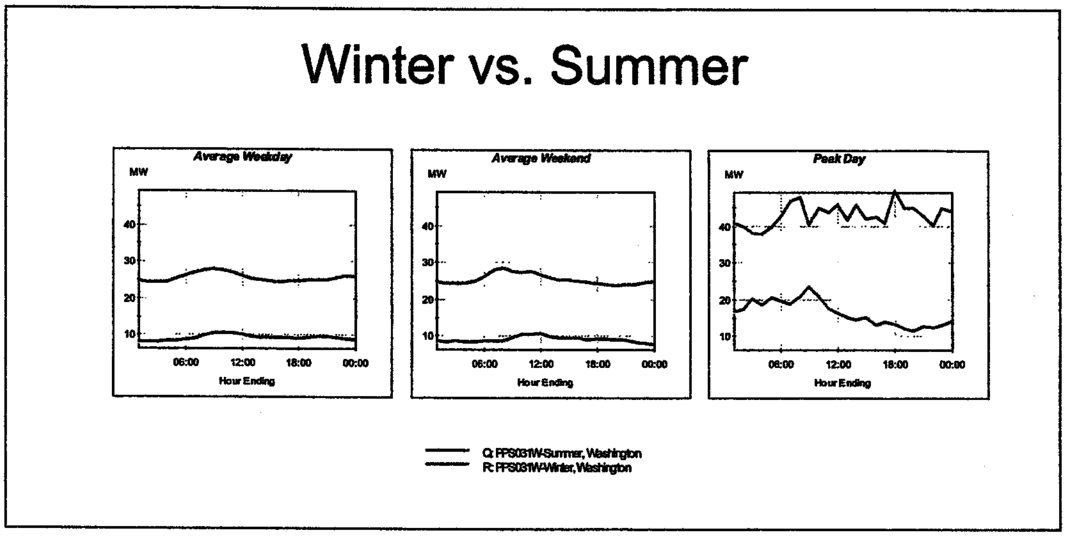


Figure 21 – Pumping (WA) Winter vs. Summer

Figure 22 presents a summary of the achieved relative precision[9] associated with the Pumping (WA) class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. The precision for this class reflects the high volatility of the load.

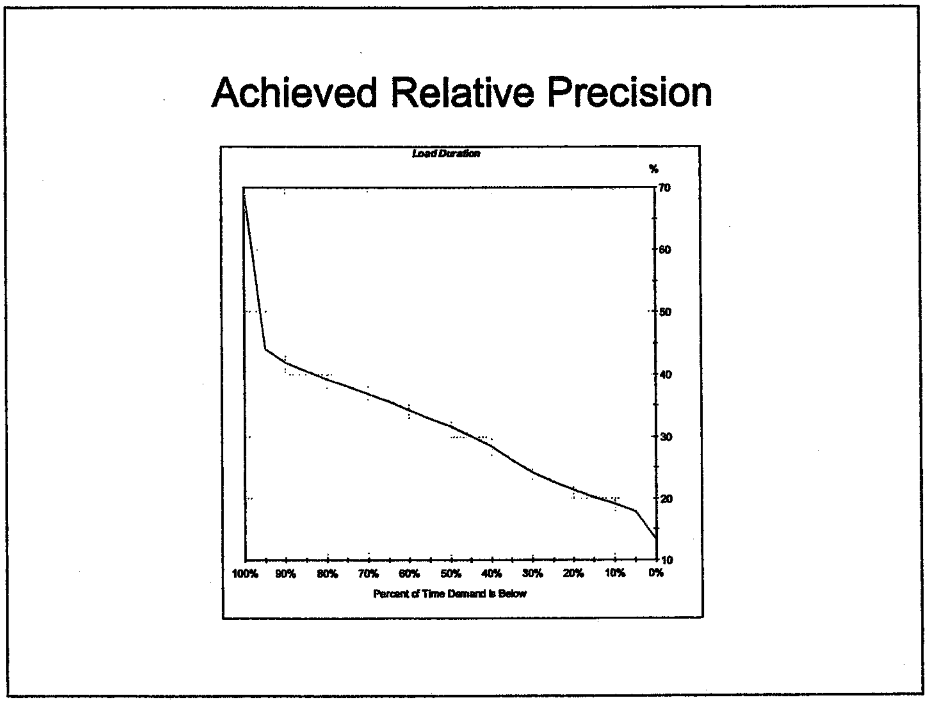


Figure 22 – Pumping (WA) Achieved Relative Precision

Table 25 presents summary statistics for the Pumping (WA) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[9] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 49% in May to a high of 73% in July. The Pumping (WA) load is not coincident with the system peak displaying a system peak coincidence factor of over 80% for only two of the 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	5,382	Fri Jan 30, 2009 8:00AM	14.4	7.2	50%	Mon Jan 26, 2009 8:00AM	10.0	69%
Feb-09	4,848	Sat Feb 21, 2009 12:00AM	12.7	7.2	57%	Tue Feb 10, 2009 8:00AM	5.1	40%
Mar-09	5,654	Sat Mar 21, 2009 12:00PM	13.7	7.6	56%	Wed Mar 11, 2009 9:00AM	7.6	55%
Apr-09	7,385	Mon Apr 27, 2009 8:00AM	17.9	10.3	57%	Wed Apr 1, 2009 12:00PM	11.8	66%
May-09	17,104	Sun May 31, 2009 7:00AM	46.7	23.0	49%	Fri May 29, 2009 5:00PM	39.1	84%
Jun-09	23,390	Fri Jun 5, 2009 6:00PM	49.1	32.5	66%	Thu Jun 4, 2009 7:00PM	31.7	64%
Jul-09	25,329	Fri Jul 3, 2009 7:00AM	46.7	34.0	73%	Mon Jul 27, 2009 6:00PM	26.7	57%
Aug-09	21,490	Sat Aug 1, 2009 11:00PM	43.2	28.9	67%	Mon Aug 3, 2009 6:00PM	37.8	88%
Sep-09	15,049	Wed Sep 2, 2009 10:00AM	36.4	20.9	57%	Wed Sep 2, 2009 6:00PM	27.0	74%
Oct-09	8,431	Fri Oct 2, 2009 9:00AM	22.8	11.3	50%	Mon Oct 12, 2009 9:00AM	9.9	43%
Nov-09	5,811	Sat Nov 14, 2009 2:00PM	14.7	8.1	55%	Mon Nov 30, 2009 6:00PM	10.2	69%
Dec-09	7,170	Sat Dec 12, 2009 3:00AM	15.8	9.6	61%	Tue Dec 8, 2009 7:00PM	9.9	63%
Annual	147,045	Annual Class Peak	49.1	16.8	34%	Annual System Peak	9.9	20%

Table 25 – Pumping (WA) Summary Statistics (Totals – MW)

Table 26 presents the same information as Table 25 but on a per-account basis. The average Pumping (WA) customer uses 62,287 kWh with an average demand of 20.8 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	2,280	Fri Jan 30, 2009 8:00AM	6.1	3.1	50%	Mon Jan 26, 2009 8:00AM	4.2	69%
Feb-09	2,054	Sat Feb 21, 2009 12:00AM	5.4	3.1	57%	Tue Feb 10, 2009 8:00AM	2.2	40%
Mar-09	2,395	Sat Mar 21, 2009 12:00PM	5.8	3.2	56%	Wed Mar 11, 2009 9:00AM	3.2	56%
Apr-09	3,128	Mon Apr 27, 2009 8:00AM	7.6	4.3	57%	Wed Apr 1, 2009 12:00PM	5.0	66%
May-09	7,245	Sun May 31, 2009 7:00AM	19.8	9.7	49%	Fri May 29, 2009 5:00PM	16.5	84%
Jun-09	9,908	Fri Jun 5, 2009 6:00PM	20.8	13.8	66%	Thu Jun 4, 2009 7:00PM	13.4	64%
Jul-09	10,729	Fri Jul 3, 2009 7:00AM	19.8	14.4	73%	Mon Jul 27, 2009 6:00PM	11.3	57%
Aug-09	9,103	Sat Aug 1, 2009 11:00PM	18.3	12.2	67%	Mon Aug 3, 2009 6:00PM	16.0	88%
Sep-09	6,375	Wed Sep 2, 2009 10:00AM	15.4	8.9	57%	Wed Sep 2, 2009 6:00PM	11.4	74%
Oct-09	3,571	Fri Oct 2, 2009 9:00AM	9.7	4.8	50%	Mon Oct 12, 2009 9:00AM	4.2	43%
Nov-09	2,461	Sat Nov 14, 2009 2:00PM	6.2	3.4	55%	Mon Nov 30, 2009 6:00PM	4.3	69%
Dec-09	3,037	Sat Dec 12, 2009 3:00AM	6.7	4.1	61%	Tue Dec 8, 2009 7:00PM	4.2	63%
Annual	62,287	Annual Class Peak	20.8	7.1	34%	Annual System Peak	4.2	20%

Table 26 – Pumping (WA) Summary Statistics (Means – kW)

2.3.6 Street and Area Lights

In the first stage analysis, the lighting classes were represented by "deemed profiles." The deemed profile provides an estimate of the load based on billing data and daylight hours.

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 23 presents the results of the reconciled hourly expansion analysis for the Street and Area Lights (WA) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The lighting loads track the nighttime hours. The Street and Area Lights (WA) class peaks on Wednesday, January 7, 2009 at 9 PM. The peak demand was 7.5 MW.

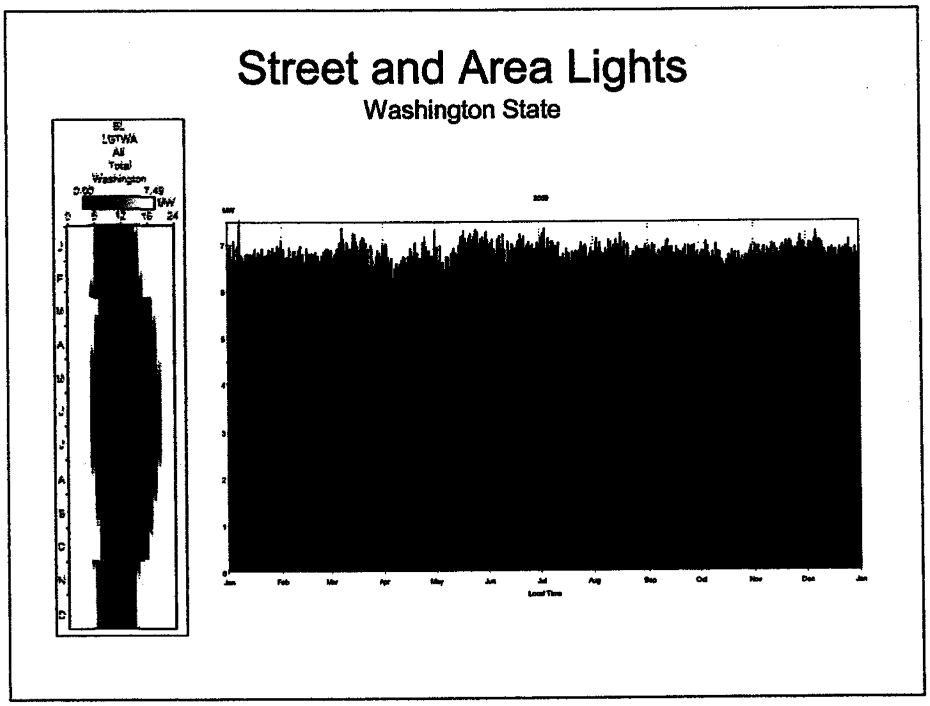


Figure 23 – Street and Area Lights (WA) Class Load

Figure 24 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The lighting class displays similar average weekday and weekend profiles by season. The longer winter hours are evident.

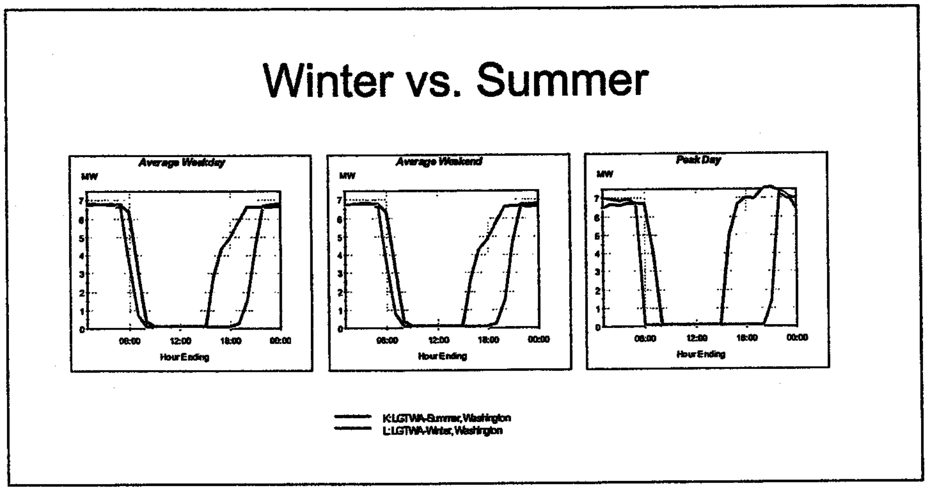


Figure 24 – Street and Area Lights (WA) Winter vs. Summer

The relative precision was not calculated for the Street and Area Lights (WA) rate class since the total class load is a deemed profile.

Table 27 presents summary statistics for the Street and Area Lights (WA) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

Monthly load factors ranged from a low of 32% in June and July to a high of 60% in December. The Street and Area Lights (WA) class load is only coincident with the system peak during the winter months of November and December with coincident factors of 96% and 94%, respectively. The class peak load is not at all coincident with the system peak during all other months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	3,060	Wed Jan 7, 2009 9:00PM	7.5	4.1	55%	Mon Jan 26, 2009 8:00AM	-	0%
Feb-09	2,516	Thu Feb 12, 2009 6:00AM	6.9	3.7	54%	Tue Feb 10, 2009 8:00AM	-	0%
Mar-09	2,478	Sun Mar 8, 2009 4:00AM	7.3	3.3	46%	Wed Mar 11, 2009 9:00AM	-	0%
Apr-09	2,020	Sat Apr 25, 2009 3:00AM	7.1	2.8	39%	Wed Apr 1, 2009 12:00PM	-	0%
May-09	1,845	Mon May 25, 2009 2:00AM	7.3	2.5	34%	Fri May 29, 2009 5:00PM	-	0%
Jun-09	1,638	Wed Jun 10, 2009 4:00AM	7.2	2.3	32%	Thu Jun 4, 2009 7:00PM	-	0%
Jul-09	1,760	Fri Jul 3, 2009 10:00PM	7.3	2.4	32%	Mon Jul 27, 2009 6:00PM	-	0%
Aug-09	2,041	Sun Aug 16, 2009 9:00PM	7.2	2.7	38%	Mon Aug 3, 2009 6:00PM	-	0%
Sep-09	2,289	Sat Sep 12, 2009 11:00PM	7.1	3.2	45%	Wed Sep 2, 2009 6:00PM	-	0%
Oct-09	2,657	Mon Oct 5, 2009 12:00AM	7.0	3.6	51%	Mon Oct 12, 2009 9:00AM	-	0%
Nov-09	2,951	Sat Nov 28, 2009 1:00AM	7.1	4.1	57%	Mon Nov 30, 2009 6:00PM	6.8	96%
Dec-09	3,204	Mon Dec 7, 2009 3:00AM	7.2	4.3	60%	Tue Dec 8, 2009 7:00PM	6.8	94%
Annual	28,458	Annual Class Peak	7.5	3.2	43%	Annual System Peak	6.8	91%

Table 27 – Street and Area Lights (WA) Summary Statistics (Totals – MW)

2.4 Class Load Profiles – Idaho

The following sections present the results of the reconciled class load for each of the rate classes in Idaho.

2.4.1 Residential

The sample data was expanded by post-stratifying the Residential (ID) rate class. Table 28 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
ID	1	Residential	1	8,492	200,118,441	37,107	25	1,484.3
ID	1	Residential	2	12,055	223,835,430	21,946	6	3,657.7
ID	1	Residential	3	16,042	238,110,237	17,132	11	1,557.5
ID	1	Residential	4	21,708	252,250,256	13,608	16	850.5
ID	1	Residential	5	320,797	277,136,024	9,635	19	507.1
Class Totals					1,191,450,388	99,428	77	

Table 28 – Residential (ID) Post-Stratification

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 25 presents the results of the reconciled hourly expansion analysis for the Residential (ID) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The dominance of the winter load is clearly evident with bi-modal peaks occurring in the morning and early evening periods. The Residential (ID) class peaks on Sunday, December 6, 2009 at 8 PM. The class peak demand was 319 MW.

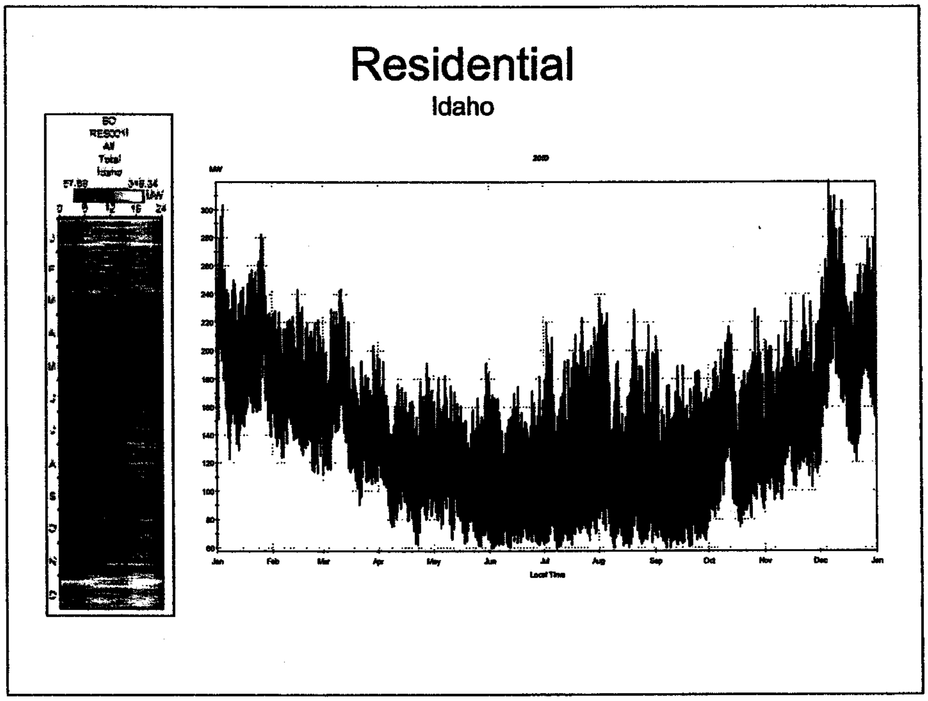


Figure 25 – Residential (ID) Class Load

Figure 26 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The winter bi-modal peak is clearly evident in the weekday and peak day profiles. The weekend profiles display a similar level of magnitude with a higher load factor (i.e., flatter load shape) when compared to the weekday profiles.

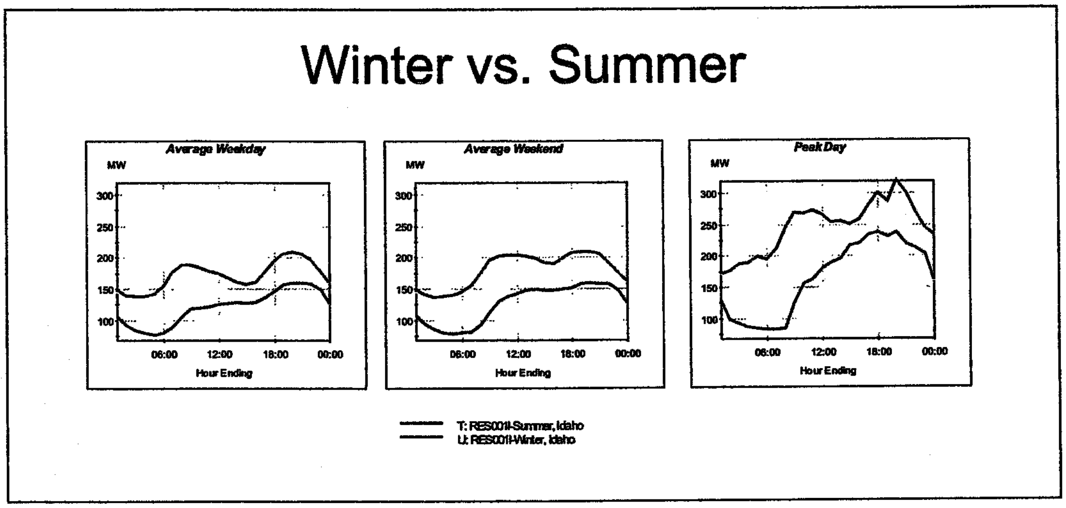


Figure 26 – Residential (ID) Winter vs. Summer

Figure 27 presents a summary of the achieved relative precision[10] associated with the Residential (ID) class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. For example, 60% of all hours are at or below a precision of ±15.9%. The majority of hours (i.e., 90% of all hours) were at or below ±20.1%.

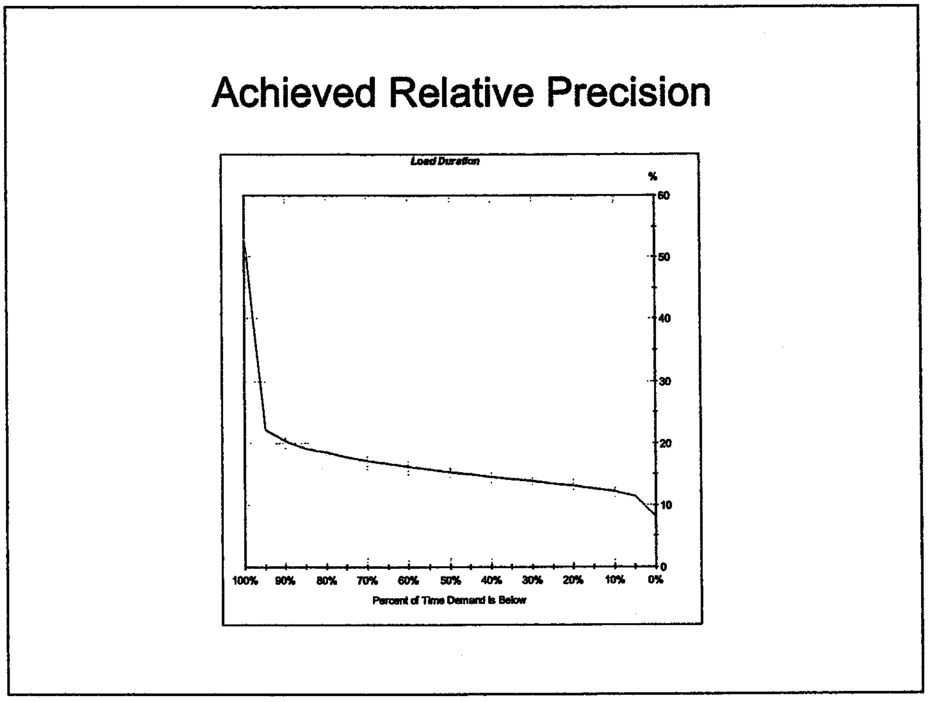


Figure 27 – Residential (ID) Achieved Relative Precision

Table 29 presents summary statistics for the Residential (ID) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[10] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 53% in August to a high of 70% in February. The Residential (ID) load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for 11 of the 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	148,873	Sun Jan 4, 2009 6:00PM	302	200	66%	Mon Jan 26, 2009 8:00AM	281	93%
Feb-09	113,927	Sun Feb 15, 2009 12:00PM	242	170	70%	Tue Feb 10, 2009 8:00AM	212	88%
Mar-09	116,336	Wed Mar 11, 2009 9:00AM	243	157	65%	Wed Mar 11, 2009 9:00AM	243	100%
Apr-09	89,131	Wed Apr 1, 2009 9:00PM	193	124	64%	Wed Apr 1, 2009 12:00PM	172	89%
May-09	85,794	Sat May 30, 2009 2:00PM	190	115	61%	Fri May 29, 2009 5:00PM	122	64%
Jun-09	79,102	Sun Jun 28, 2009 9:00PM	180	110	61%	Thu Jun 4, 2009 7:00PM	153	85%
Jul-09	94,974	Wed Jul 22, 2009 7:00PM	222	128	57%	Mon Jul 27, 2009 6:00PM	190	86%
Aug-09	93,485	Sat Aug 1, 2009 8:00PM	236	126	53%	Mon Aug 3, 2009 6:00PM	217	92%
Sep-09	80,483	Tue Sep 1, 2009 8:00PM	209	112	54%	Wed Sep 2, 2009 6:00PM	189	90%
Oct-09	101,375	Mon Oct 26, 2009 9:00PM	228	136	60%	Mon Oct 12, 2009 9:00AM	215	95%
Nov-09	110,692	Sun Nov 22, 2009 5:00PM	237	154	65%	Mon Nov 30, 2009 6:00PM	214	90%
Dec-09	154,517	Sun Dec 6, 2009 8:00PM	319	208	65%	Tue Dec 8, 2009 7:00PM	283	89%
Annual	1,268,688	Annual Class Peak	319	145	45%	Annual System Peak	283	89%

Table 29 – Residential (ID) Summary Statistics (Totals – MW)

Table 30 presents the same information as Table 29 but on a per-account basis. The average Residential (ID) customer uses 12,740 kWh with an average demand of 3.2 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	1,495	Sun Jan 4, 2009 6:00PM	3.0	2.0	66%	Mon Jan 26, 2009 8:00AM	2.8	93%
Feb-09	1,144	Sun Feb 15, 2009 12:00PM	2.4	1.7	70%	Tue Feb 10, 2009 8:00AM	2.1	88%
Mar-09	1,168	Wed Mar 11, 2009 9:00AM	2.4	1.6	65%	Wed Mar 11, 2009 9:00AM	2.4	100%
Apr-09	895	Wed Apr 1, 2009 9:00PM	1.9	1.2	64%	Wed Apr 1, 2009 12:00PM	1.7	89%
May-09	862	Sat May 30, 2009 2:00PM	1.9	1.2	61%	Fri May 29, 2009 5:00PM	1.2	64%
Jun-09	794	Sun Jun 28, 2009 9:00PM	1.8	1.1	61%	Thu Jun 4, 2009 7:00PM	1.5	85%
Jul-09	954	Wed Jul 22, 2009 7:00PM	2.2	1.3	57%	Mon Jul 27, 2009 6:00PM	1.9	86%
Aug-09	939	Sat Aug 1, 2009 8:00PM	2.4	1.3	53%	Mon Aug 3, 2009 6:00PM	2.2	92%
Sep-09	808	Tue Sep 1, 2009 8:00PM	2.1	1.1	54%	Wed Sep 2, 2009 6:00PM	1.9	90%
Oct-09	1,018	Mon Oct 26, 2009 9:00PM	2.3	1.4	60%	Mon Oct 12, 2009 9:00AM	2.2	94%
Nov-09	1,112	Sun Nov 22, 2009 5:00PM	2.4	1.5	65%	Mon Nov 30, 2009 6:00PM	2.2	90%
Dec-09	1,552	Sun Dec 6, 2009 8:00PM	3.2	2.1	65%	Tue Dec 8, 2009 7:00PM	2.8	88%
Annual	12,740	Annual Class Peak	3.2	1.5	45%	Annual System Peak	2.8	88%

Table 30 – Residential (ID) Summary Statistics (Means – kW)

2.4.2 General Service

The sample data was expanded by post-stratifying the General Service (ID) rate class. Table 31 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
ID	11	General Service	1	8,255	26,324,338	8,576	13	659.7
ID	11	General Service	2	16,031	32,792,612	2,791	12	232.6
ID	11	General Service	3	25,887	36,493,385	1,808	9	200.9
ID	11	General Service	4	42,803	40,252,946	1,225	10	122.5
ID	11	General Service	5	146,888	45,649,982	756	10	75.6
		Schedule 11 Total			181,513,264	15,156	54	
ID	12	General Service	1	39,311	23,724,490	1,307	8	163.4
ID	12	General Service	2	60,733	27,967,721	565	5	113.0
ID	12	General Service	3	81,247	29,954,524	424	5	84.8
ID	12	General Service	4	104,838	31,605,663	342	9	38.0
ID	12	General Service	5	354,050	33,617,643	272	3	90.7
		Schedule 12 Total			146,870,041	2,910	30	
		Rate Class Totals			328,383,305	18,066	84	

Table 31 – General Service (ID) Post-Stratification

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 28 presents the results of the reconciled hourly expansion analysis for the General Service (ID) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. Daytimes loads are dominant throughout the year with higher load and load factor during the winter months. The General Service (ID) class peaks on Wednesday, December 9, 2009 at 5 PM. The class peak demand was 77 MW.

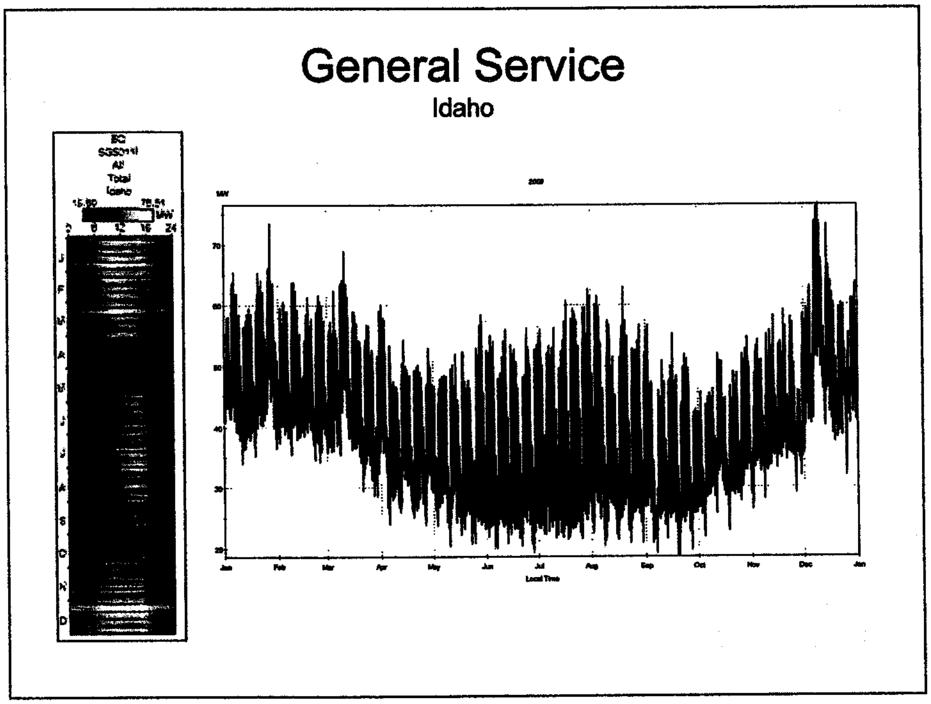


Figure 28 – General Service (ID) Class Load

Figure 29 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. Winter loads are clearly higher than summer loads with a flatter load shape on both weekdays and weekends. The summer weekday load almost reaches the magnitude of the winter weekday load, but for fewer hours during the day.

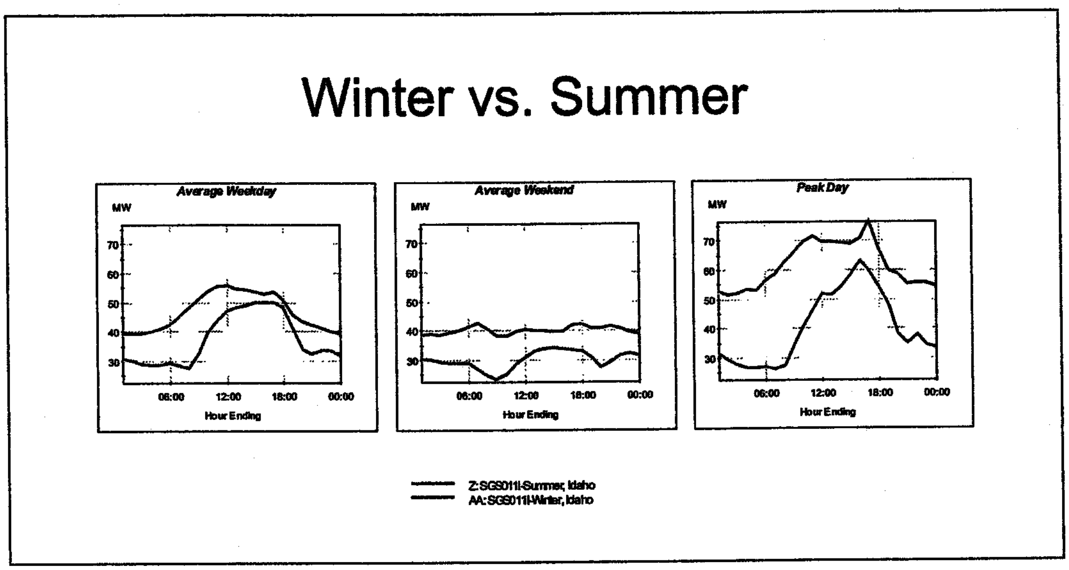


Figure 29 – General Service (ID) Winter vs. Summer

Figure 30 presents a summary of the achieved relative precision[11] associated with the General Service (ID) rate class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. For example, 60% of all hours are at or below a precision of ±13%. The majority of hours (i.e., 90% of all hours) were at or below ±15.07%.

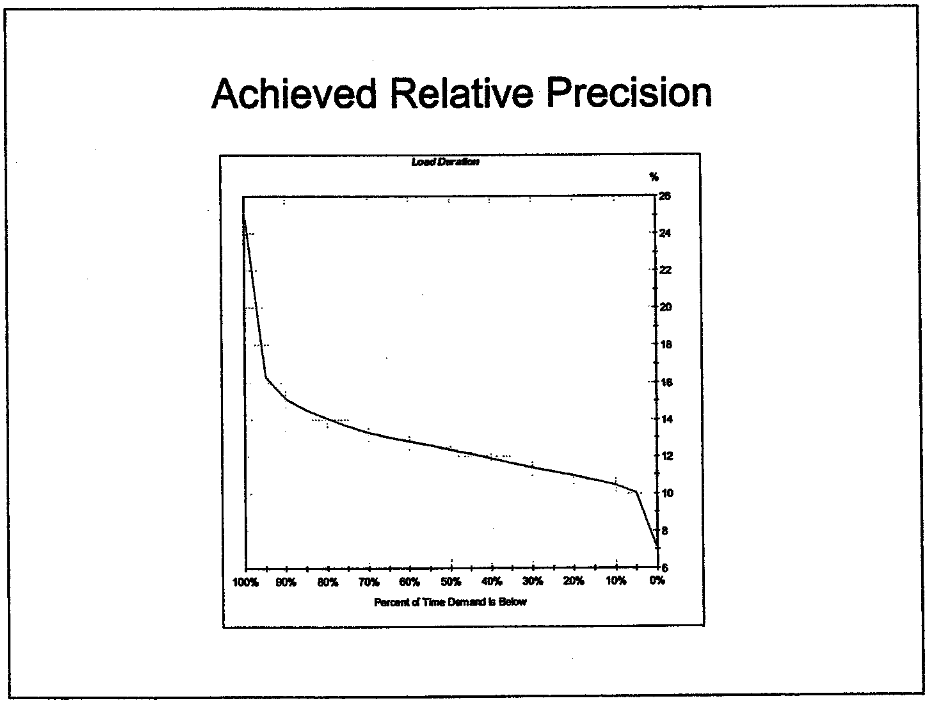


Figure 30 – General Service (ID) Achieved Relative Precision

Table 32 presents summary statistics for the General Service (ID) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[11] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 57% in August and September to a high of 73% in February. The General Service (ID) load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for ten of the 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	35,788	Tue Jan 27, 2009 5:00PM	73	48	66%	Mon Jan 26, 2009 8:00AM	64	87%
Feb-09	31,008	Tue Feb 10, 2009 11:00AM	64	46	73%	Tue Feb 10, 2009 8:00AM	52	82%
Mar-09	32,467	Wed Mar 11, 2009 12:00PM	69	44	64%	Wed Mar 11, 2009 9:00AM	60	88%
Apr-09	26,480	Wed Apr 1, 2009 1:00PM	60	37	61%	Wed Apr 1, 2009 12:00PM	59	98%
May-09	25,129	Fri May 29, 2009 5:00PM	58	34	58%	Fri May 29, 2009 5:00PM	58	100%
Jun-09	24,553	Wed Jun 24, 2009 5:00PM	56	34	61%	Thu Jun 4, 2009 7:00PM	43	78%
Jul-09	27,126	Thu Jul 30, 2009 5:00PM	62	36	59%	Mon Jul 27, 2009 6:00PM	56	91%
Aug-09	26,570	Wed Aug 19, 2009 4:00PM	63	36	57%	Mon Aug 3, 2009 6:00PM	57	90%
Sep-09	23,288	Wed Sep 2, 2009 3:00PM	56	32	57%	Wed Sep 2, 2009 6:00PM	50	89%
Oct-09	26,564	Thu Oct 29, 2009 12:00PM	54	36	66%	Mon Oct 12, 2009 9:00AM	42	78%
Nov-09	29,484	Thu Nov 19, 2009 12:00PM	59	41	69%	Mon Nov 30, 2009 6:00PM	54	92%
Dec-09	37,732	Wed Dec 9, 2009 5:00PM	77	51	66%	Tue Dec 8, 2009 7:00PM	61	80%
Annual	346,191	Annual Class Peak	77	40	52%	Annual System Peak	61	80%

Table 32 – General Service (ID) Summary Statistics (Totals – MW)

Table 33 presents the same information as Table 32 but on a per-account basis. The average General Service (ID) customer uses 17,989 kWh with an average demand of 4.0 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	1,860	Tue Jan 27, 2009 5:00PM	3.8	2.5	66%	Mon Jan 26, 2009 8:00AM	3.3	87%
Feb-09	1,611	Tue Feb 10, 2009 11:00AM	3.3	2.4	73%	Tue Feb 10, 2009 8:00AM	2.7	82%
Mar-09	1,687	Wed Mar 11, 2009 12:00PM	3.6	2.3	64%	Wed Mar 11, 2009 9:00AM	3.1	88%
Apr-09	1,376	Wed Apr 1, 2009 1:00PM	3.1	1.9	61%	Wed Apr 1, 2009 12:00PM	3.1	98%
May-09	1,306	Fri May 29, 2009 5:00PM	3.0	1.8	58%	Fri May 29, 2009 5:00PM	3.0	100%
Jun-09	1,276	Wed Jun 24, 2009 5:00PM	2.9	1.8	61%	Thu Jun 4, 2009 7:00PM	2.3	77%
Jul-09	1,410	Thu Jul 30, 2009 5:00PM	3.2	1.9	59%	Mon Jul 27, 2009 6:00PM	2.9	90%
Aug-09	1,381	Wed Aug 19, 2009 4:00PM	3.3	1.9	57%	Mon Aug 3, 2009 6:00PM	2.9	90%
Sep-09	1,210	Wed Sep 2, 2009 3:00PM	2.9	1.7	57%	Wed Sep 2, 2009 6:00PM	2.6	89%
Oct-09	1,380	Thu Oct 29, 2009 12:00PM	2.8	1.9	66%	Mon Oct 12, 2009 9:00AM	2.2	77%
Nov-09	1,532	Thu Nov 19, 2009 12:00PM	3.1	2.1	69%	Mon Nov 30, 2009 6:00PM	2.8	92%
Dec-09	1,961	Wed Dec 9, 2009 5:00PM	4.0	2.6	66%	Tue Dec 8, 2009 7:00PM	3.2	80%
Annual	17,989	Annual Class Peak	4.0	2.1	52%	Annual System Peak	3.2	80%

Table 33 – General Service (ID) Summary Statistics (Means – kW)

2.4.3 Large General Service

The sample data was expanded by post-stratifying the Large General Service (ID) rate class. Table 34 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
ID	21	Large General Service	1	222,049	94,591,059	587	5	117.4
ID	21	Large General Service	2	375,015	105,970,230	369	4	92.3
ID	21	Large General Service	3	672,002	117,998,904	241	4	60.3
ID	21	Large General Service	4	1,629,465	138,112,151	132	4	33.0
ID	21	Large General Service	5	9,041,873	172,972,060	57	10	5.7
ID	21	Large General Service-Primary	6	14,519,981	77,163,956	32	4	8.0
Class Totals					706,808,361	1,418	31	

Table 34 – Large General Service (ID) Post-Stratification

In the second stage of the analysis, loss factors of 1.079 and 1.054 (provided by Avista) were applied to the hourly Large General Service (ID) and Large General Service-Primary (ID) rate class expansions, respectively.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 31 presents the results of the reconciled hourly expansion analysis for the Large General Service (ID) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The summer load tends to be slightly higher than the winter load. The Large General Service (ID) class peaks on Tuesday, August 4, 2009 at 3 PM. The peak demand was just under 163 MW.

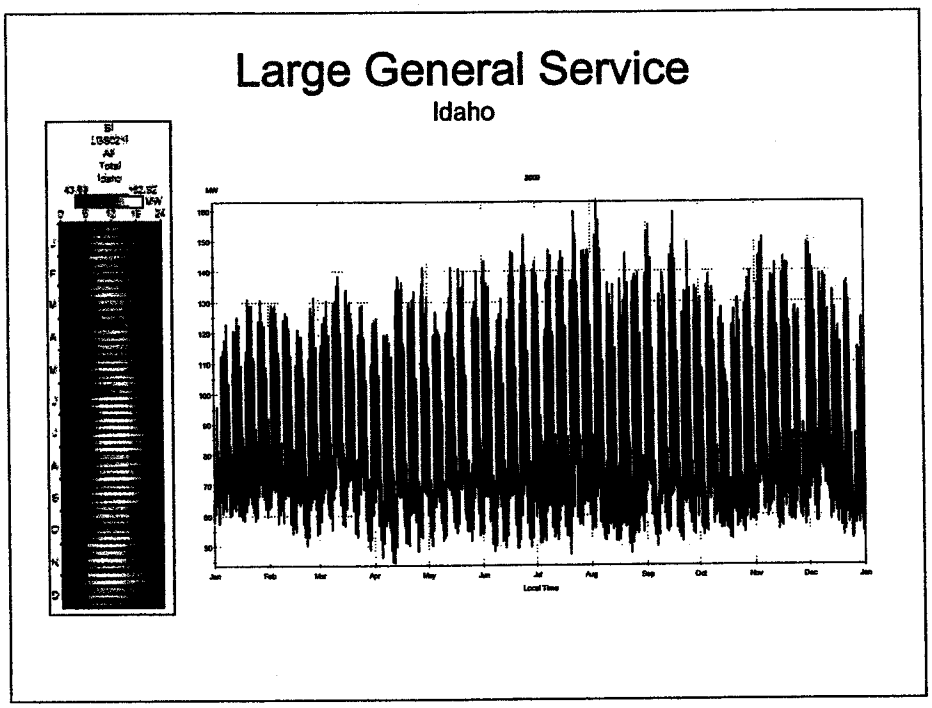


Figure 31 – Large General Service (ID) Class Load

Figure 32 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The winter and summer load shapes are very similar in both magnitude and shape. The weekend profiles are substantially lower than their weekday counterparts.

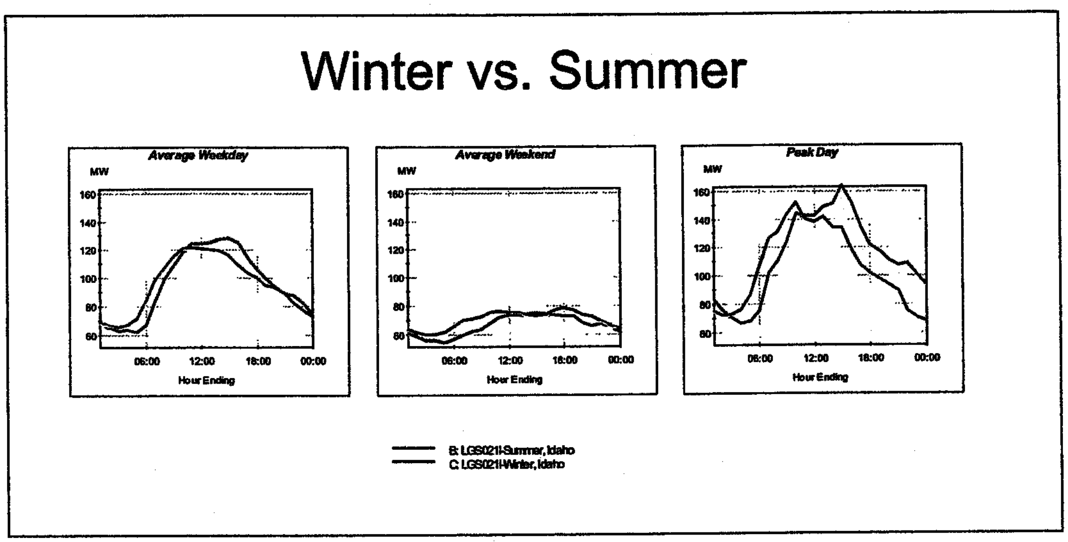


Figure 32 – Large General Service (ID) Winter vs. Summer

Figure 33 presents a summary of the achieved relative precision[12] associated with the Large General Service (ID) class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. For example, 60% of all hours are at or below a precision of ±15.5%. The majority of hours (i.e., 90% of all hours) were at or below ±19.3%.

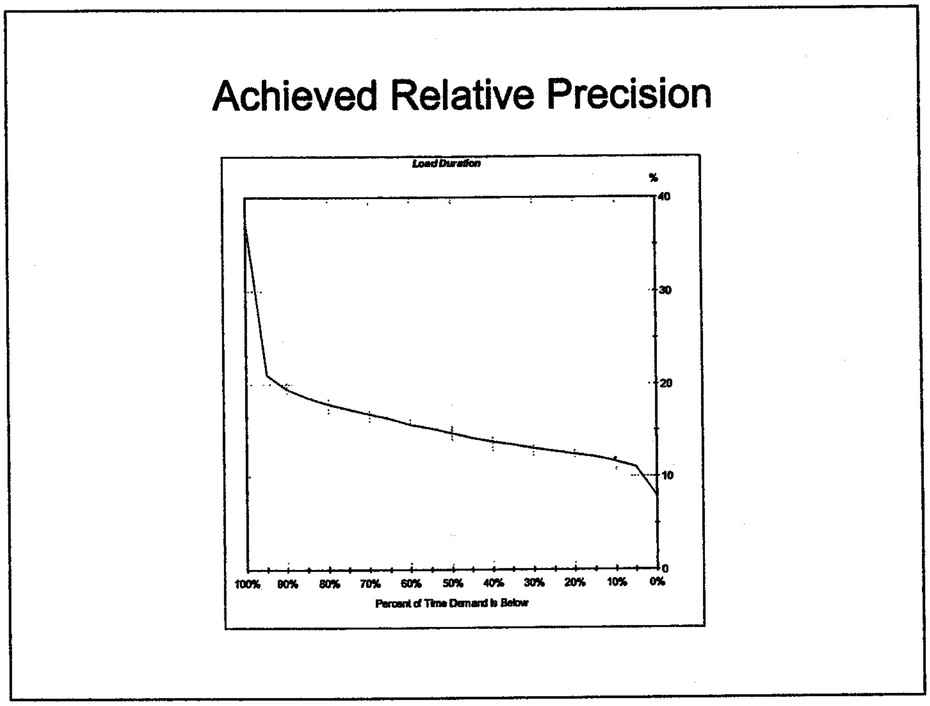


Figure 33 – Large General Service (ID) Achieved Relative Precision

Table 35 presents summary statistics for the Large General Service (ID) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[12] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 53% in August to a high of 65% in January and February. The Large General Service (ID) class load is somewhat coincident with the system peak displaying a system peak coincidence factor of over 80% for five of the 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	63,217	Tue Jan 20, 2009 10:00AM	130	85	65%	Mon Jan 26, 2009 8:00AM	113	87%
Feb-09	57,532	Thu Feb 26, 2009 10:00AM	131	86	65%	Tue Feb 10, 2009 8:00AM	106	81%
Mar-09	64,060	Thu Mar 12, 2009 11:00AM	138	86	63%	Wed Mar 11, 2009 9:00AM	121	88%
Apr-09	59,662	Tue Apr 28, 2009 11:00AM	141	83	59%	Wed Apr 1, 2009 12:00PM	118	84%
May-09	61,320	Thu May 14, 2009 1:00PM	141	82	59%	Fri May 29, 2009 5:00PM	114	81%
Jun-09	62,320	Wed Jun 24, 2009 2:00PM	151	87	57%	Thu Jun 4, 2009 7:00PM	104	68%
Jul-09	67,317	Wed Jul 22, 2009 3:00PM	159	90	57%	Mon Jul 27, 2009 6:00PM	117	74%
Aug-09	64,717	Tue Aug 4, 2009 3:00PM	163	87	53%	Mon Aug 3, 2009 6:00PM	119	73%
Sep-09	63,378	Wed Sep 16, 2009 3:00PM	159	88	55%	Wed Sep 2, 2009 6:00PM	120	76%
Oct-09	61,889	Thu Oct 29, 2009 2:00PM	140	83	60%	Mon Oct 12, 2009 9:00AM	107	77%
Nov-09	64,095	Thu Nov 5, 2009 10:00AM	151	89	59%	Mon Nov 30, 2009 6:00PM	110	73%
Dec-09	66,308	Tue Dec 1, 2009 1:00PM	148	89	60%	Tue Dec 8, 2009 7:00PM	115	77%
Annual	755,816	Annual Class Peak	163	86	53%	Annual System Peak	115	71%

Table 35 – Large General Service (ID) Summary Statistics (Totals – MW)

Table 36 presents the same information as Table 35 but on a per-account basis. The average Large General Service (ID) customer uses 518,570 kWh with an average demand of 118.8 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	43,374	Tue Jan 20, 2009 10:00AM	89.4	58.3	65%	Mon Jan 26, 2009 8:00AM	77.4	87%
Feb-09	39,473	Thu Feb 26, 2009 10:00AM	89.8	58.7	65%	Tue Feb 10, 2009 8:00AM	72.9	81%
Mar-09	43,952	Thu Mar 12, 2009 11:00AM	94.6	59.2	63%	Wed Mar 11, 2009 9:00AM	83.1	88%
Apr-09	40,934	Tue Apr 28, 2009 11:00AM	96.6	56.9	59%	Wed Apr 1, 2009 12:00PM	81.2	84%
May-09	42,072	Thu May 14, 2009 1:00PM	96.5	56.6	59%	Fri May 29, 2009 5:00PM	78.1	81%
Jun-09	42,758	Wed Jun 24, 2009 2:00PM	103.9	59.4	57%	Thu Jun 4, 2009 7:00PM	71.0	68%
Jul-09	46,187	Wed Jul 22, 2009 3:00PM	109.1	62.1	57%	Mon Jul 27, 2009 6:00PM	80.2	74%
Aug-09	44,403	Tue Aug 4, 2009 3:00PM	111.8	59.7	53%	Mon Aug 3, 2009 6:00PM	81.7	73%
Sep-09	43,484	Wed Sep 16, 2009 3:00PM	109.0	60.4	55%	Wed Sep 2, 2009 6:00PM	82.5	76%
Oct-09	42,463	Thu Oct 29, 2009 2:00PM	95.7	57.1	60%	Mon Oct 12, 2009 9:00AM	73.4	77%
Nov-09	43,976	Thu Nov 5, 2009 10:00AM	103.3	61.0	59%	Mon Nov 30, 2009 6:00PM	75.5	73%
Dec-09	45,494	Tue Dec 1, 2009 1:00PM	101.7	61.2	60%	Tue Dec 8, 2009 7:00PM	78.8	77%
Annual	518,570	Annual Class Peak	111.8	59.2	53%	Annual System Peak	78.8	71%

Table 36 – Large General Service (ID) Summary Statistics (Means – kW)

2.4.4 Extra Large General Service

Data for all customers in the Extra Large General Service (ID) were available, so the population count and sample size are the same, and each site's case weight is one.

In the second stage of the analysis, a loss factor of 1.054 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 34 presents the results of the reconciled hourly expansion analysis for the Extra Large General Service (ID) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The Extra Large General Service (ID) class peaks on Wednesday, September 2, 2009 at 1 PM. The peak demand was just under 42 MW.

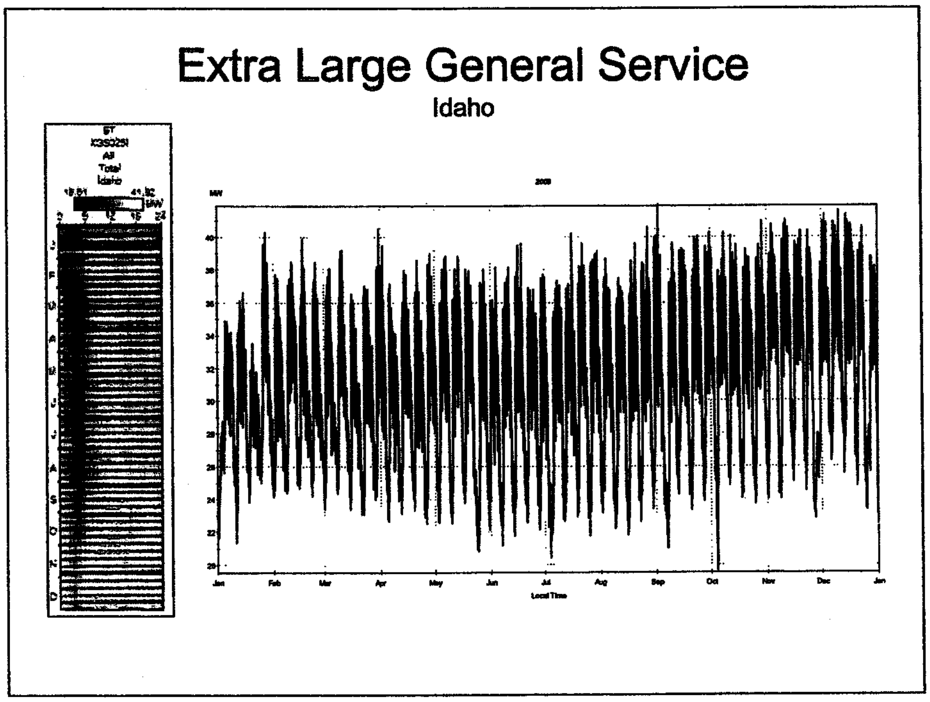


Figure 34 – Extra Large General Service (ID) Class Load

Figure 35 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The summer and winter load shapes are similar in magnitude displaying a lower and flatter load shape on weekends when compared to weekends.

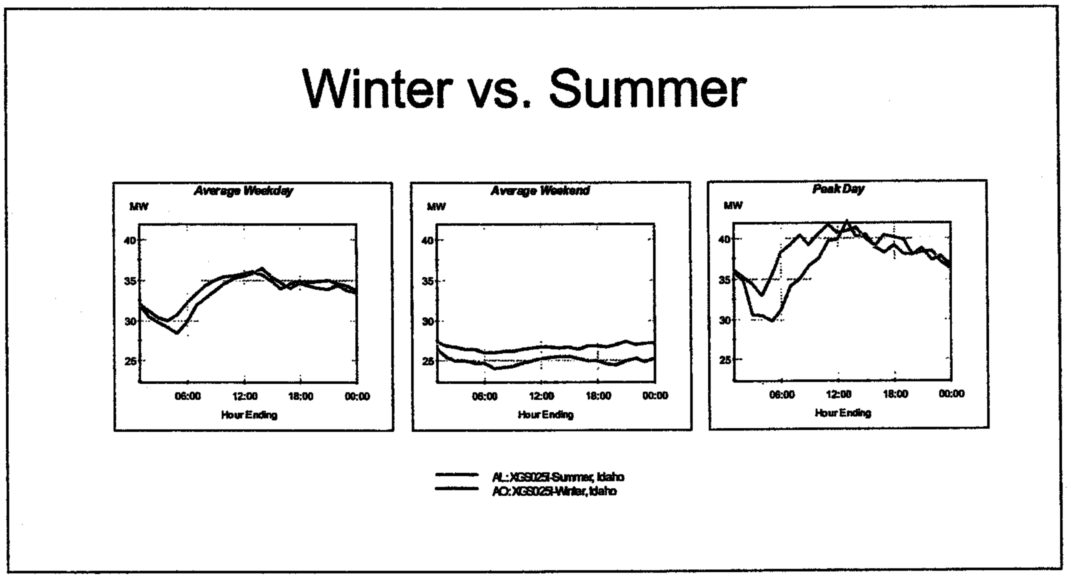


Figure 35 – Extra Large General Service (ID) Winter vs. Summer

The relative precision was perfect since the data for all of the customers in the class were available for the full 12 month period examined.

Table 37 presents summary statistics for the Extra Large General Service (ID) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

Monthly load factors ranged from a low of 74% in January to a high of 81% in December. The Extra Large General Service (ID) class load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for all 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	22,054	Tue Jan 27, 2009 10:00AM	40.2	29.6	74%	Mon Jan 26, 2009 8:00AM	37.7	94%
Feb-09	20,590	Tue Feb 17, 2009 1:00PM	39.8	30.6	77%	Tue Feb 10, 2009 8:00AM	35.9	90%
Mar-09	22,501	Tue Mar 31, 2009 2:00PM	40.4	30.3	75%	Wed Mar 11, 2009 9:00AM	37.0	92%
Apr-09	21,988	Thu Apr 2, 2009 2:00PM	39.4	30.5	78%	Wed Apr 1, 2009 12:00PM	37.5	95%
May-09	22,401	Thu May 7, 2009 12:00PM	38.8	30.1	78%	Fri May 29, 2009 5:00PM	34.1	88%
Jun-09	21,976	Thu Jun 18, 2009 2:00PM	39.5	30.5	77%	Thu Jun 4, 2009 7:00PM	36.6	93%
Jul-09	22,858	Thu Jul 16, 2009 2:00PM	40.1	30.7	77%	Mon Jul 27, 2009 6:00PM	37.1	92%
Aug-09	22,771	Thu Aug 27, 2009 2:00PM	40.5	30.6	76%	Mon Aug 3, 2009 6:00PM	34.8	86%
Sep-09	22,923	Wed Sep 2, 2009 1:00PM	41.9	31.8	76%	Wed Sep 2, 2009 6:00PM	39.0	93%
Oct-09	24,068	Thu Oct 29, 2009 1:00PM	40.8	32.4	79%	Mon Oct 12, 2009 9:00AM	36.8	90%
Nov-09	23,498	Wed Nov 11, 2009 11:00AM	41.0	32.6	80%	Mon Nov 30, 2009 6:00PM	37.0	90%
Dec-09	25,058	Thu Dec 10, 2009 11:00AM	41.5	33.7	81%	Tue Dec 8, 2009 7:00PM	39.6	95%
Annual	272,686	Annual Class Peak	41.9	31.1	74%	Annual System Peak	39.6	94%

Table 37 – Extra Large General Service (ID) Summary Statistics (Totals – MW)

Table 38 presents the same information as Table 37 but on a per-account basis. The average Extra Large General Service (ID) customer uses 34,085,693 kWh with an average demand of 5,240 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	2,756,775	Tue Jan 27, 2009 10:00AM	5,024	3,705	74%	Mon Jan 26, 2009 8:00AM	4,711	94%
Feb-09	2,573,810	Tue Feb 17, 2009 1:00PM	4,974	3,830	77%	Tue Feb 10, 2009 8:00AM	4,492	90%
Mar-09	2,812,651	Tue Mar 31, 2009 2:00PM	5,053	3,786	75%	Wed Mar 11, 2009 9:00AM	4,623	91%
Apr-09	2,748,449	Thu Apr 2, 2009 2:00PM	4,925	3,817	78%	Wed Apr 1, 2009 12:00PM	4,686	95%
May-09	2,800,131	Thu May 7, 2009 12:00PM	4,844	3,764	78%	Fri May 29, 2009 5:00PM	4,258	88%
Jun-09	2,747,024	Thu Jun 18, 2009 2:00PM	4,938	3,815	77%	Thu Jun 4, 2009 7:00PM	4,569	93%
Jul-09	2,857,296	Thu Jul 16, 2009 2:00PM	5,014	3,840	77%	Mon Jul 27, 2009 6:00PM	4,637	92%
Aug-09	2,846,395	Thu Aug 27, 2009 2:00PM	5,065	3,826	76%	Mon Aug 3, 2009 6:00PM	4,349	86%
Sep-09	2,865,322	Wed Sep 2, 2009 1:00PM	5,240	3,980	76%	Wed Sep 2, 2009 6:00PM	4,874	93%
Oct-09	3,008,468	Thu Oct 29, 2009 1:00PM	5,106	4,044	79%	Mon Oct 12, 2009 9:00AM	4,604	90%
Nov-09	2,937,153	Wed Nov 11, 2009 11:00AM	5,118	4,074	80%	Mon Nov 30, 2009 6:00PM	4,625	90%
Dec-09	3,132,219	Thu Dec 10, 2009 11:00AM	5,190	4,210	81%	Tue Dec 8, 2009 7:00PM	4,951	95%
Annual	34,085,693	Annual Class Peak	5,240	3,891	74%	Annual System Peak	4,951	94%

Table 38 – Extra Large General Service (ID) Summary Statistics (Means – kW)

2.4.5 Extra Large General Service – CP

One customer is included in the Extra Large General Service – CP (ID) rate class. Since the class is comprised of one customer, the population count and the sample size are the same (that is, one), and the sample case weight is one.

In the second stage of the analysis, a loss factor of 1.054 (provided by Avista) was applied to the non-generation portion of the Extra Large General Service – CP (ID) load served by Avista.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 36 presents the results of the reconciled hourly expansion analysis for the Extra Large General Service – CP (ID) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The Extra Large General Service – CP (ID) rate class displays a constant load throughout the year. The class peaks on Wednesday, December 16, 2009 at 1 AM. The peak demand was 112.7 MW.

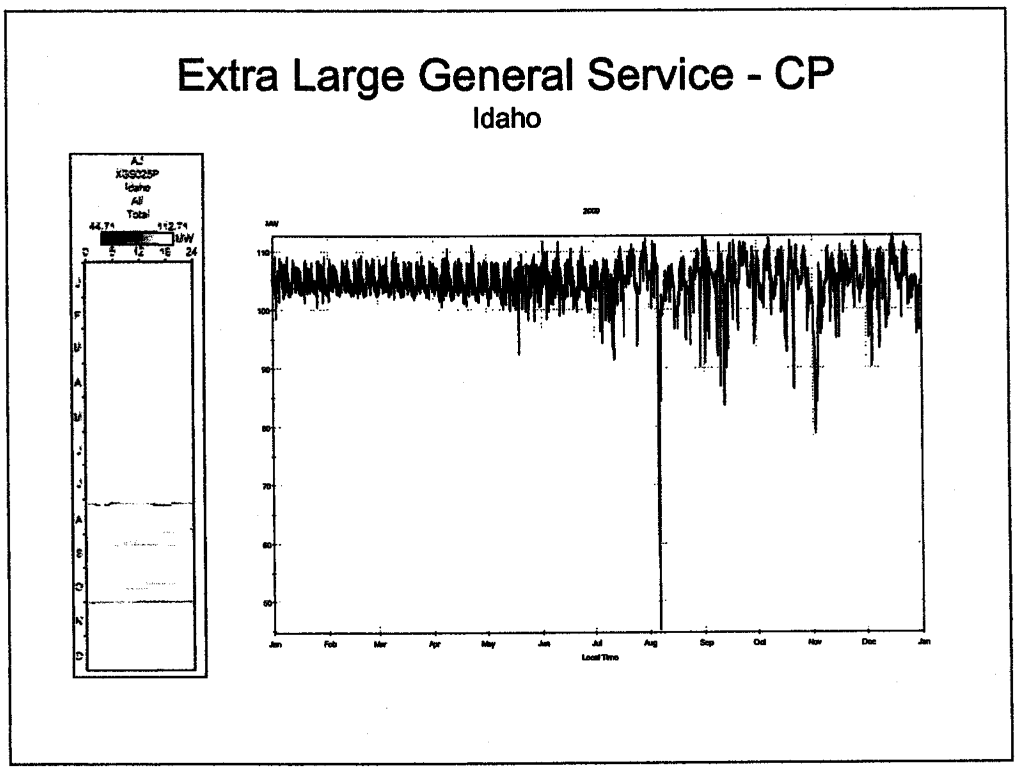


Figure 36 – Extra Large General Service - CP (ID) Class Load

Figure 37 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The summer and winter load shapes are very similar in magnitude with a flatter load shape on the weekends when compared to weekdays.

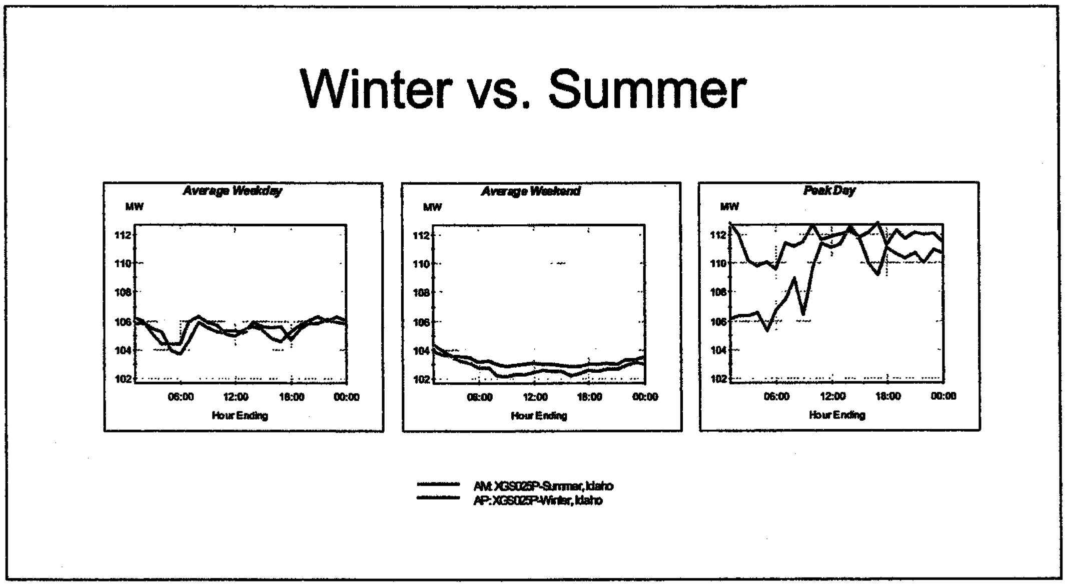


Figure 37 – Extra Large General Service – CP (ID) Winter vs. Summer

The relative precision was perfect since the data for the one customer in the class were available for the full 12 month period examined.

Table 39 presents summary statistics for the Extra Large General Service - CP (ID) rate class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

Monthly load factors ranged from a low of 92% in August to a high of 96% in January, February, and March. The Extra Large General Service – CP (ID) class load is very coincident with the system peak displaying a system peak coincidence factor of over 80% for all 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	78,020	Fri Jan 2, 2009 2:00PM	109.0	104.9	96%	Mon Jan 26, 2009 8:00AM	107.0	98%
Feb-09	70,448	Fri Feb 20, 2009 2:00AM	109.1	104.8	96%	Tue Feb 10, 2009 8:00AM	105.9	97%
Mar-09	77,837	Tue Mar 10, 2009 9:00AM	109.7	104.8	96%	Wed Mar 11, 2009 9:00AM	105.7	96%
Apr-09	75,344	Thu Apr 23, 2009 3:00AM	110.9	104.7	94%	Wed Apr 1, 2009 12:00PM	107.8	97%
May-09	77,501	Wed May 20, 2009 9:00PM	109.4	104.2	95%	Fri May 29, 2009 5:00PM	102.6	94%
Jun-09	75,281	Tue Jun 2, 2009 1:00AM	111.5	104.6	94%	Thu Jun 4, 2009 7:00PM	106.6	96%
Jul-09	78,267	Thu Jul 30, 2009 3:00PM	111.9	105.2	94%	Mon Jul 27, 2009 6:00PM	107.2	96%
Aug-09	76,978	Mon Aug 31, 2009 5:00PM	112.7	103.5	92%	Mon Aug 3, 2009 6:00PM	110.3	98%
Sep-09	75,532	Thu Sep 17, 2009 7:00PM	111.6	104.9	94%	Wed Sep 2, 2009 6:00PM	108.7	97%
Oct-09	78,055	Wed Oct 7, 2009 2:00PM	112.1	104.9	94%	Mon Oct 12, 2009 9:00AM	108.6	97%
Nov-09	74,720	Mon Nov 30, 2009 10:00AM	111.5	103.6	93%	Mon Nov 30, 2009 6:00PM	108.4	97%
Dec-09	78,065	Wed Dec 16, 2009 1:00AM	112.7	104.9	93%	Tue Dec 8, 2009 7:00PM	100.7	89%
Annual	916,050	Annual Class Peak	112.7	104.6	93%	Annual System Peak	100.7	89%

Table 39 – Extra Large General Service – CP (ID) Summary Statistics (Totals – MW)

2.4.6 Pumping

The sample data was expanded by post-stratifying the Pumping (ID) rate class. Table 40 presents the post-stratification used in the sample expansion analysis. The table presents the jurisdiction, schedule, rate class, strata, maximum annual use in each stratum, the population total annual use in the stratum, the population count, the minimum available sample points in the historical sample and the case weight calculated as the population count divided by the minimum available sample.

Jurisdiction	Schedule	Rate Class	Strata	Maximum Value Annual kWh	Population Total (Annual kWh)	Population Count	Sample Size	Case Weight
ID	31	Pumping Service	1	36,632	6,523,274	970	3	323.3
ID	31	Pumping Service	2	128,384	9,479,973	142	6	23.7
ID	31	Pumping Service	3	348,496	11,805,724	58	3	19.3
ID	31	Pumping Service	4	766,131	13,772,882	26	4	6.5
ID	31	Pumping Service	5	2,067,882	17,603,626	14	7	2.0
Class Totals					59,185,479	1,210	23	

Table 40 – Pumping (ID) Post-Stratification

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly expansions.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 38 presents the results of the reconciled hourly expansion analysis for the Pumping (ID) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The dominance of the summer load is clearly evident with only minimal load in the winter months. The Pumping (ID) class peaks on Friday, July 24, 2009 at 8 AM. The peak demand was about 48 MW.

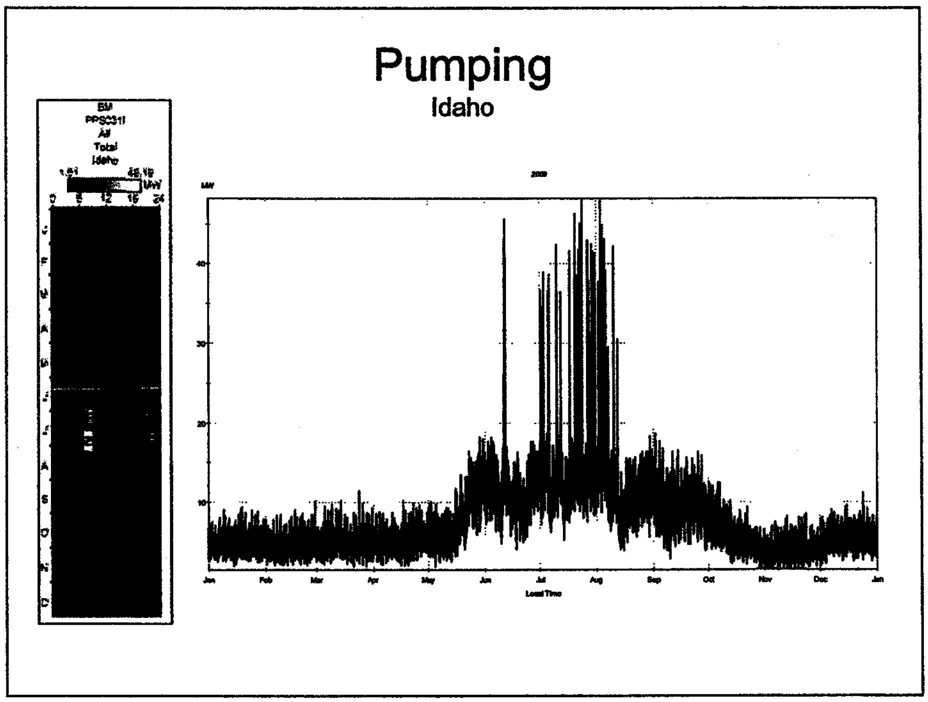


Figure 38 – Pumping (ID) Class Load

Figure 39 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The seasonal pumping load is highest during the summer period. The average weekday and weekend load shapes are very similar by season and differ dramatically from the class peak load.

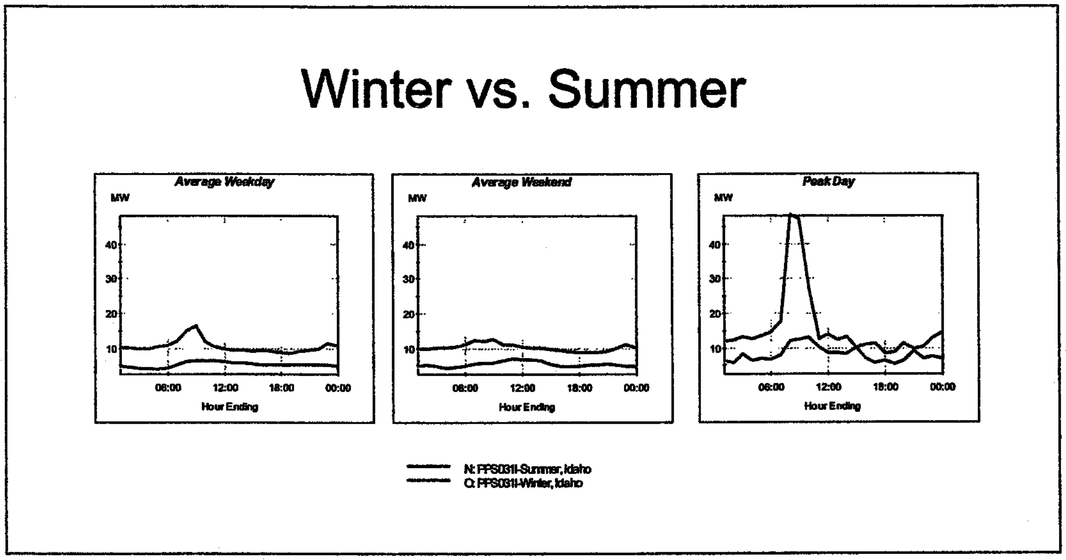


Figure 39 – Pumping (ID) Winter vs. Summer

Figure 40 presents a summary of the achieved relative precision[13] associated with the Pumping (ID) class analysis. The figure presents the percentage of time the achieved precision was at or below the specific level. The precision for this class reflects the high volatility of the load.

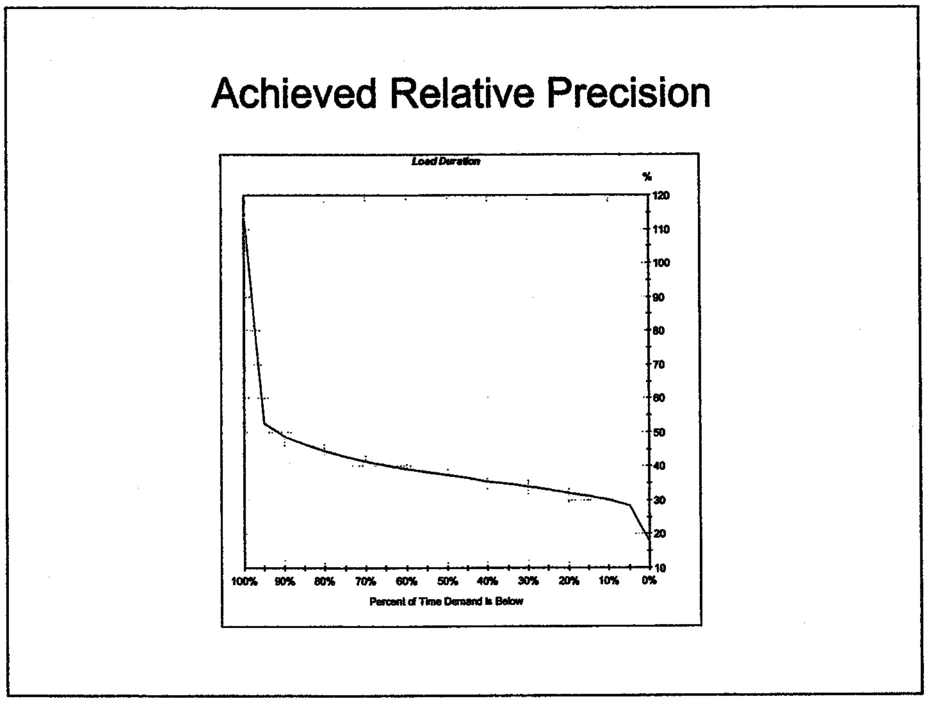


Figure 40 – Pumping (ID) Achieved Relative Precision

Table 41 presents summary statistics for the Pumping (ID) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

[13] Statistical precision is a measure of how much customer-to-customer variation there is in the data and is used to construct boundaries around our estimates. In load research applications we typically target precision levels of ±10% for the majority of hours in the analysis period.

Monthly load factors ranged from a low of 24% in August to a high of 50% in September. The Pumping (ID) class load is not coincident with the system peak displaying a system peak coincidence factor of 80% or greater for none of the 12 months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	3,315	Mon Jan 19, 2009 1:00PM	9.2	4.5	48%	Mon Jan 26, 2009 8:00AM	5.6	60%
Feb-09	2,985	Sat Feb 28, 2009 11:00AM	10.0	4.4	44%	Tue Feb 10, 2009 8:00AM	5.2	51%
Mar-09	3,467	Tue Mar 24, 2009 11:00AM	11.3	4.7	41%	Wed Mar 11, 2009 9:00AM	4.6	41%
Apr-09	3,553	Fri Apr 17, 2009 12:00PM	10.1	4.9	49%	Wed Apr 1, 2009 12:00PM	5.4	54%
May-09	5,787	Fri May 29, 2009 8:00AM	18.1	7.8	43%	Fri May 29, 2009 5:00PM	9.5	52%
Jun-09	8,440	Fri Jun 12, 2009 8:00AM	45.4	11.7	26%	Thu Jun 4, 2009 7:00PM	14.4	32%
Jul-09	10,153	Fri Jul 24, 2009 8:00AM	48.2	13.7	28%	Mon Jul 27, 2009 6:00PM	11.2	23%
Aug-09	8,591	Mon Aug 3, 2009 9:00AM	47.9	11.6	24%	Mon Aug 3, 2009 6:00PM	11.7	24%
Sep-09	6,667	Wed Sep 2, 2009 7:00AM	18.5	9.3	50%	Wed Sep 2, 2009 6:00PM	7.3	40%
Oct-09	3,968	Thu Oct 1, 2009 10:00AM	12.4	5.3	43%	Mon Oct 12, 2009 9:00AM	9.2	74%
Nov-09	2,774	Mon Nov 23, 2009 10:00AM	8.4	3.9	46%	Mon Nov 30, 2009 6:00PM	4.7	56%
Dec-09	3,727	Thu Dec 24, 2009 10:00AM	11.0	5.0	45%	Tue Dec 8, 2009 7:00PM	3.9	35%
Annual	63,428	Annual Class Peak	48.2	7.2	15%	Annual System Peak	3.9	8%

Table 41 – Pumping (ID) Summary Statistics (Totals – MW)

Table 42 presents the same information as Table 41 but on a per-account basis. The average Pumping (WA) customer uses 48,339 kWh with an average demand of 36.7 kW at the time of the class peak.

Month	Monthly Energy Use (kWh)	Timing of Class Peak	Class Peak Demand (kW)	Average Demand (kW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (kW)	Coincidence Factor (%)
Jan-09	2,526	Mon Jan 19, 2009 1:00PM	7.0	3.4	48%	Mon Jan 26, 2009 8:00AM	4.3	60%
Feb-09	2,275	Sat Feb 28, 2009 11:00AM	7.7	3.4	44%	Tue Feb 10, 2009 8:00AM	3.9	51%
Mar-09	2,642	Tue Mar 24, 2009 11:00AM	8.6	3.6	41%	Wed Mar 11, 2009 9:00AM	3.5	41%
Apr-09	2,708	Fri Apr 17, 2009 12:00PM	7.7	3.8	49%	Wed Apr 1, 2009 12:00PM	4.1	54%
May-09	4,411	Fri May 29, 2009 8:00AM	13.8	5.9	43%	Fri May 29, 2009 5:00PM	7.2	52%
Jun-09	6,432	Fri Jun 12, 2009 8:00AM	34.6	8.9	26%	Thu Jun 4, 2009 7:00PM	11.0	32%
Jul-09	7,737	Fri Jul 24, 2009 8:00AM	36.7	10.4	28%	Mon Jul 27, 2009 6:00PM	8.5	23%
Aug-09	6,547	Mon Aug 3, 2009 9:00AM	36.5	8.8	24%	Mon Aug 3, 2009 6:00PM	8.9	25%
Sep-09	5,081	Wed Sep 2, 2009 7:00AM	14.1	7.1	50%	Wed Sep 2, 2009 6:00PM	5.6	40%
Oct-09	3,024	Thu Oct 1, 2009 10:00AM	9.5	4.1	43%	Mon Oct 12, 2009 9:00AM	7.0	74%
Nov-09	2,115	Mon Nov 23, 2009 10:00AM	6.4	2.9	46%	Mon Nov 30, 2009 6:00PM	3.6	56%
Dec-09	2,840	Thu Dec 24, 2009 10:00AM	8.4	3.8	45%	Tue Dec 8, 2009 7:00PM	2.9	35%
Annual	48,339	Annual Class Peak	36.7	5.5	15%	Annual System Peak	2.9	8%

Table 42 – Pumping (ID) Summary Statistics (Means – kW)

2.4.7 Street and Area Lights

In the first stage analysis, the lighting classes were represented by "deemed profiles." The deemed profile provides an estimate of the load based on billing data and daylight hours.

In the second stage of the analysis, a loss factor of 1.079 (provided by Avista) was applied to the hourly loads.

Finally, in the third stage of the analysis, the unaccounted for energy was allocated to each class based on the class's contribution to the system demand for that particular hour.

Figure 41 presents the results of the reconciled hourly expansion analysis for the Street and Area Lights (ID) rate class. The figure displays the EnergyPrint to the left of the more standard two-dimensional x-y plot. As a reminder, the vertical form of the EnergyPrint displays time on the x-axis, day of the year on the y-axis and the magnitude of load on the z-axis. The magnitude of load is displayed as a color gradient with low levels of load in the black-blue spectrum and high levels of load in the yellow-white spectrum. The lighting loads track the nighttime hours. The Street and Area Lights (ID) class peaks on Wednesday, January 7, 2009 at 9 PM. The peak demand was 3.9 MW.

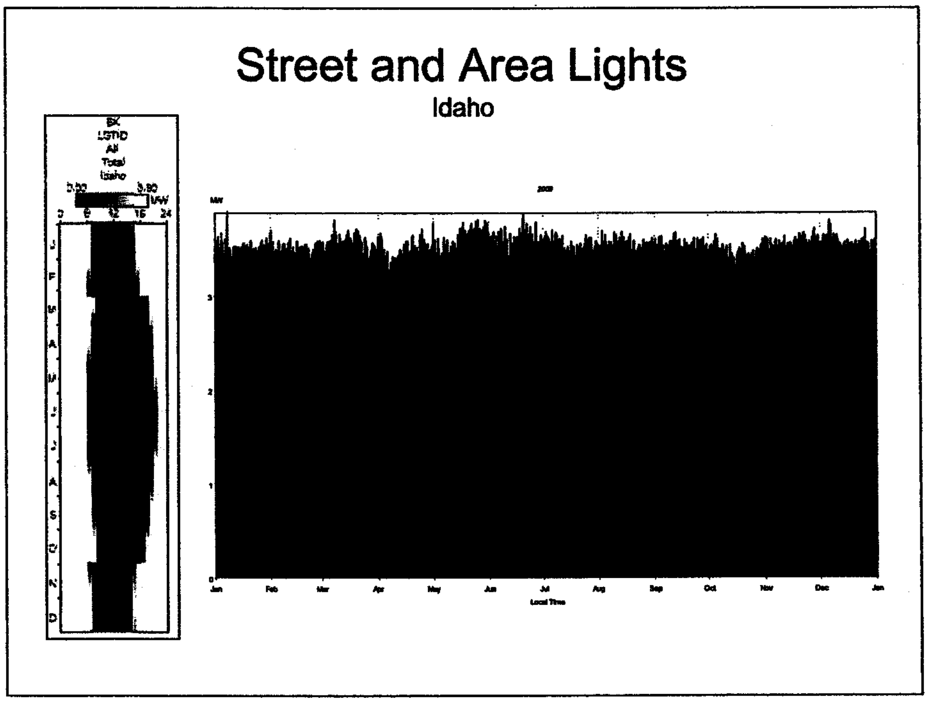


Figure 41 – Street and Area Lights (ID) Class Load

Figure 42 highlights the differences between the winter and summer by displaying the average weekday, average weekend day, and peak days. Winter is defined as the October through March period and summer is defined as April through September. The lighting class displays similar average weekday and weekend profiles by season. The longer winter hours are evident.

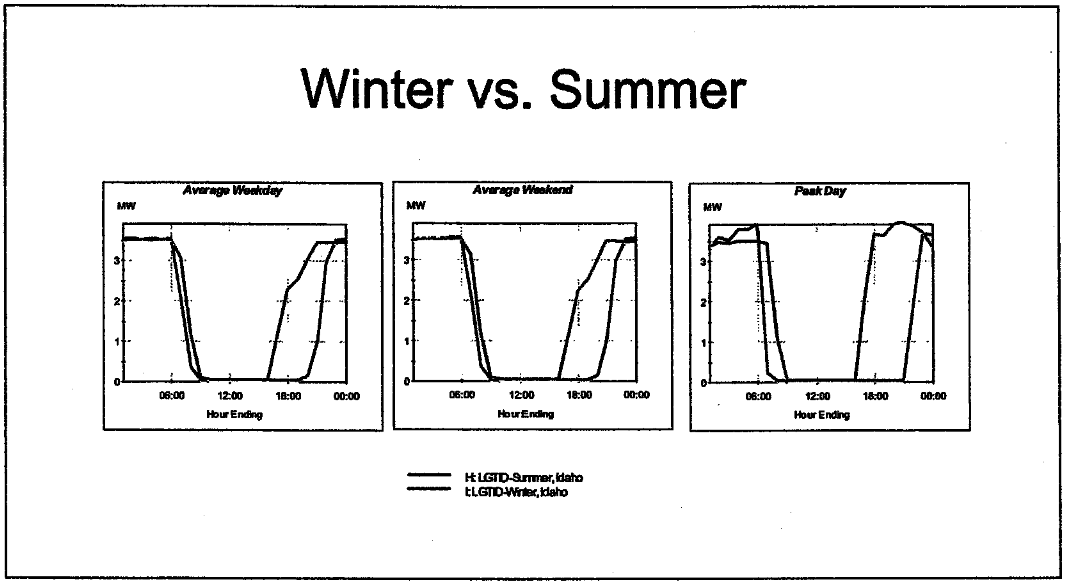


Figure 42 – Street and Area Lights (ID) Winter vs. Summer

The relative precision was not calculated for the Street and Area Lights (ID) rate class since the total class load is a deemed profile.

Table 43 presents summary statistics for the Street and Area Lights (ID) class load after applying losses and reconciliation to the system load. The table displays class totals and includes the monthly energy use, the timing of the class peak demand, the magnitude of the class peak demand, the average demand, the load factor based on the class peak demand, the timing of the system peak demand, the class demand at the time of system peak (i.e., coincident), and the coincidence factor calculated as the coincident peak divided by the class peak.

Monthly load factors ranged from a low of 33% in June to a high of 57% in December. The Street and Area Lights (ID) class load is only coincident with the system peak during the winter months of November and December with coincident factors of 96% and 93%, respectively. The class peak load is not at all coincident with the system peak during most other months.

Month	Monthly Energy Use (MWh)	Timing of Class Peak	Class Peak Demand (MW)	Average Demand (MW)	Load Factor (%)	Timing of System Peak	Class Demand @ System Peak (MW)	Coincidence Factor (%)
Jan-09	1,545	Wed Jan 7, 2009 9:00PM	3.9	2.1	53%	Mon Jan 26, 2009 8:00AM	0.4	11%
Feb-09	1,286	Sun Feb 1, 2009 7:00AM	3.7	1.9	52%	Tue Feb 10, 2009 8:00AM	-	0%
Mar-09	1,288	Sun Mar 8, 2009 4:00AM	3.8	1.7	46%	Wed Mar 11, 2009 9:00AM	0.2	6%
Apr-09	1,074	Sat Apr 25, 2009 3:00AM	3.7	1.5	40%	Wed Apr 1, 2009 12:00PM	-	0%
May-09	1,010	Tue May 26, 2009 6:00AM	3.8	1.4	36%	Fri May 29, 2009 5:00PM	-	0%
Jun-09	913	Sat Jun 20, 2009 6:00AM	3.9	1.3	33%	Thu Jun 4, 2009 7:00PM	-	0%
Jul-09	965	Mon Jul 6, 2009 4:00AM	3.7	1.3	35%	Mon Jul 27, 2009 6:00PM	-	0%
Aug-09	1,089	Mon Aug 3, 2009 1:00AM	3.7	1.5	40%	Mon Aug 3, 2009 6:00PM	-	0%
Sep-09	1,193	Sat Sep 12, 2009 11:00PM	3.7	1.7	45%	Wed Sep 2, 2009 6:00PM	-	0%
Oct-09	1,362	Mon Oct 5, 2009 12:00AM	3.7	1.8	50%	Mon Oct 12, 2009 9:00AM	-	0%
Nov-09	1,496	Sat Nov 28, 2009 1:00AM	3.7	2.1	56%	Mon Nov 30, 2009 6:00PM	3.6	96%
Dec-09	1,612	Sun Dec 6, 2009 7:00AM	3.8	2.2	57%	Tue Dec 8, 2009 7:00PM	3.6	93%
Annual	14,833	Annual Class Peak	3.9	1.7	43%	Annual System Peak	3.6	91%

Table 43 – Street and Area Lights (ID) Summary Statistics (Totals – MW)

NATURAL GAS COST OF SERVICE STUDY

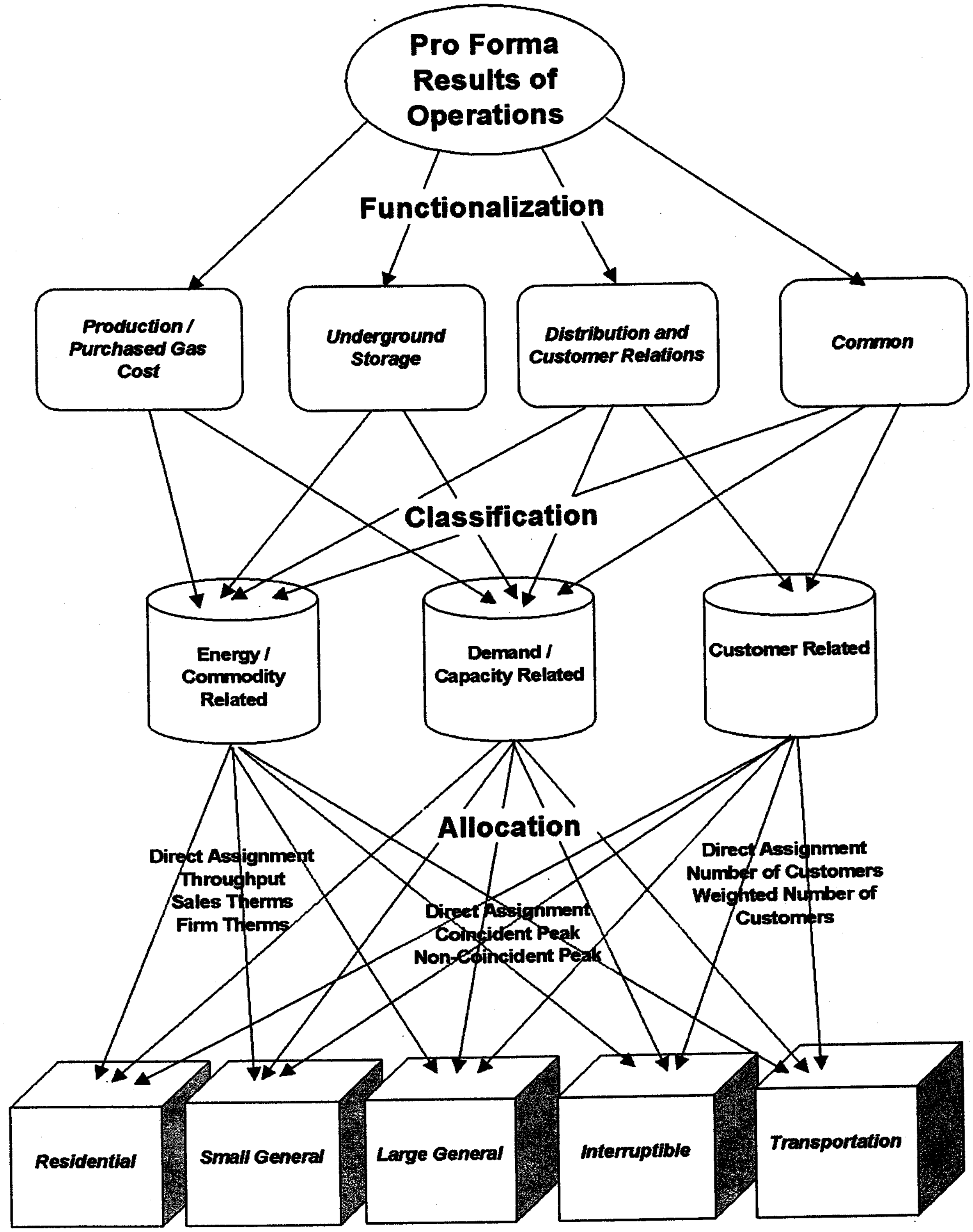
A cost of service study is an engineering-economic study, which apportions the revenue, expenses, and rate base associated with providing natural gas service to designated groups of customers. It indicates whether the revenue provided by the customers recovers the cost to serve those customers. The study results are used as a guide in determining the appropriate rate spread among the groups of customers.

There are three basic steps involved in a cost of service study: functionalization, classification, and allocation. See flow chart.

First, the expenses and rate base associated with the natural gas system under study are assigned to functional categories. The uniform system of accounts provides the basic segregation into production, underground storage, and distribution. Traditionally customer accounting, customer information, and sales expenses are included in the distribution function and administrative and general expenses and general plant rate base are allocated to all functions. In this study I have created a separate functional category for common costs. Administrative and general costs that cannot be directly assigned to the other functions have been placed in this category.

Second, the expenses and rate base items are classified into three primary cost components: Demand, commodity or customer related. Demand (capacity) related costs are allocated to rate schedules on the basis of each schedule's contribution to system peak demand. Commodity (energy) related costs are allocated based on each rate schedule's share of commodity consumption. Customer related items are allocated to rate schedules based on the number of customers within each schedule. The number of customers may be weighted by appropriate factors such as relative cost of metering equipment. In addition to these three cost components, any revenue related expense is allocated based on the proportion of revenues by rate schedule.

NATURAL GAS COST OF SERVICE STUDY FLOWCHART



Pro Forma Results of Operations by Customer Group

Exhibit No. 13
Case No. AVU-G-10-01
T. Knox, Avista
Schedule 5, p. 2 of 9

The final step is allocation of the costs to the various rate schedules utilizing the allocation factors selected for each specific cost item. These factors are derived from usage and customer information associated with the test period results of operations.

BASE CASE COST OF SERVICE STUDY

Production - Purchased Gas Costs

The Company has no natural gas production facilities serving the Idaho jurisdiction. The natural gas costs included in the production function include the cost of gas purchased to serve sales customers, pipeline transportation to get it to our system, and expenses of the gas supply department.

The demand and commodity components of account 804 have been determined directly from the weighted average cost of gas (WACOG) approved in the most recent purchased gas adjustment (PGA) filing effective November 1, 2009. The November 1, 2009 gas cost reduction to customer charges was accomplished through Schedule 155 which is excluded from base revenues. The allocation of these costs agrees with the gas costs computation used to determine pro forma results of operations.

The expenses of the gas supply department recorded in account 813 are classified as commodity related costs. The gas scheduling process includes transportation customers, so estimated scheduling dispatch labor expenses are allocated by throughput. The remaining gas supply department expenses are allocated by sales volumes.

Underground Storage

Underground storage rate base, operating and maintenance expenses are classified as commodity related and allocated to customer groups by winter throughput. This approach was proposed by commission Staff and accepted by the Idaho Public Utilities Commission in Case No. AVU-G-04-01.

Distribution Facilities Classification (Peak and Average)

Distribution mains and regulator station equipment (both general use and city gate stations) are classified Demand and Commodity using the peak and average ratio for the distribution system. Peak demand is defined as the average of the five-day sustained peaks from the most recent three years. Average daily load is calculated by dividing annual throughput by 365 (days in the year). The average daily load is divided by peak load to arrive at the system load factor of 33.68%. This proportion is classified as commodity related. The remaining 66.32% is classified as demand related. Meters, services and industrial measuring & regulating equipment are classified as customer related distribution plant. Distribution operating and maintenance expenses are classified (and allocated) in relation to the plant accounts they are associated with.

Customer Relations Distribution Cost Classification

Customer service, customer information and sales expenses are the core of the customer relations functional unit which is included with the distribution cost category. For the most part these costs are classified as customer related. Exceptions include uncollectible accounts expense, which is considered separately as a revenue conversion item, and Demand Side Management amortization expense recorded in Account 908. The demand side management investment costs and amortization expense are included with the distribution function and classified to demand and commodity by the peak and average ratio.

Distribution Cost Allocation

Demand related distribution costs are allocated to customer groups (rate schedules) by each groups' contribution to the three year average five-day sustained peak. Commodity related distribution costs are allocated to customer groups by annual throughput. Distribution main investment has been segregated into large and small mains. Small mains are defined as less than four inches, with large mains being four inches or greater. The small main costs use the same demand and commodity data, but large usage customers (Schedules 131, and 146) that connect to large system mains have been excluded from the allocations.

Most customer related costs are allocated by the annualized number of customers billed during the test period. Meter investment costs are allocated using the number of customers weighted by the relative current cost of meters in service at December 31, 2009. Services investment costs are allocated using the number of customers weighted by the relative current cost of typical service installations. Industrial measuring and regulating equipment investment costs are allocated by number of turbine meters which effectively excludes small usage customers.

Administrative and General Costs

General and intangible rate base items are allocated by the sum of Underground Storage and Distribution plant. Administrative and general expenses are segregated into plant related, labor related, revenue related and other. The plant related items are allocated based on total plant in service. Labor related items are allocated by operating and maintenance labor expense. Revenue related items are allocated by pro forma revenue. Other administrative and general expenses are allocated 50% by annual throughput (classified commodity related) and 50% by the sum of operating and maintenance expenses not including purchased gas cost or administrative & general expenses. Whenever costs are allocated by sums of other items within the study, classifications are imputed from the relationship embedded in the summed items.

Special Contract Customer Revenue

Three special contract customers receive transportation service from the Company. Rates for these customers were individually negotiated to cover any incremental costs and retain some contribution to margin. The rates for these customers are not being adjusted in this case. The revenue from these special contract customers has been segregated from general rate revenue and allocated back to all the other rate classes by relative rate base. In treating these revenues like other operating revenues their system contribution reduces costs for all rate schedules.

Revenue Conversion Items

In this study uncollectible accounts and commission fees have been classified as revenue related and are allocated by pro forma revenue. These items vary with revenue and are included in the calculation of the revenue conversion factor. Income tax expense items are allocated to schedules by net income before income tax less interest expense.

For the functional summaries on pages 2 and 3 of the cost of service study, these items are assigned to the component cost categories. The revenue related expense items have been reduced to a percent of all other costs and loaded onto each cost category b that ratio. Similarly, income tax items have been assigned to cost categories by relative rate base (as is net income).

The following matrix outlines the methodology applied in the Company Base Case natural gas cost of service study.

IPUC Case No. AVU-G-10-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Underground Storage Plant			
1	350 - 357 Underground Storage	Underground Storage	Commodity	E08 Winter throughput
	Distribution Plant			
2	374 Land	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
3	375 Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
4	376(S) Small Mains	Distribution	Demand/Commodity by Peak & Average	D02/E06 Coincident peak, annual therms (both excl lg use cust)
5	376(L) Large Mains	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
6	378 M&R General	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
7	379 M&R City Gate	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
8	380 Services	Distribution	Customer	C02, Customers weighted by current typical service cost
9	381 Meters	Distribution	Customer	C03, Customers weighted by average current meter cost
10	385 Industrial M&R	Distribution	Customer	C06, Large use customers
11	387 Other	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
	General Plant			
12	389-399 All General Plant	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Intangible Plant			
13	303 Misc Intangible Plant	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
14	303 Computer Software	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
	Reserve for Depreciation			
15	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
16	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
18	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Other Rate Base			
19	Accumulated Deferred FIT	All	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
20	Constuction Advances	Distribution	Customer	C10 Residential only
21	Gas Inventory	Underground Storage	Commodity from Underground Storage Plant	S14 Sum of Underground Storage Plant in Service
22	Gain on Sale of Office Bldg	Common	Demand/Commodity/Customer from UG & D Plant	S03 Sum of Underground Storage and Distribution Plant in Service
23	DSM Investment	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
	Purchased Gas Expenses			
24	804 Purchased Gas Cost	Production	Demand/Commodity from PGA Tracker WACOG	D05/E07 PGA Demand / PGA Commodity
25	813 Other Gas Expenses	Production	Commodity	E01/E04 Annual Throughput / Annual Sales Therms
	Underground Storage O&M			
26	814 - 837 Underground Storage Exp	Underground Storage	Commodity	E08 Winter throughput

IPUC Case No. AVU-G-10-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Distribution O&M			
1	870 OP Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
2	871 Load Dispatching	Distribution	Commodity	E01 Annual throughput
3	874 Mains & Services	Distribution	Demand/Commodity/Customer from related plant	S06 Sum of Mains and Services Plant in Service
4	875 M&R Station - General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
5	876 M&R Station - Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
6	877 M&R Station - City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
7	878 Meter & House Regulator	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
8	879 Customer Installations	Distribution	Customer	C05, Customers weighted by average current meter cost
9	880 Other OP Expenses	Distribution	Demand/Commodity/Customer from other dist expens	S04 Sum of Accounts 870 - 879 and 881 - 894
10	881 Rents	Distribution	Demand/Commodity/Customer from other dist expens	S04 Sum of Accounts 870 - 879 and 881 - 894
11	885 MT Super & Engineering	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
12	886 MT of Structures	Distribution	Demand/Commodity/Customer from Other Dist Plant	S05 Sum of accounts 376-385
13	887 MT of Mains	Distribution	Demand/Commodity from related plant	S21 Sum of Distribution Mains Plant in Service
14	889 MT of M&R General	Distribution	Demand/Commodity from related plant	S08 Sum of Meas & Reg Station - General Plant in Service
15	890 MT of M&R Industrial	Distribution	Customer from related plant	S19 Sum of Meas & Reg Station - Industrial Plant in Service
16	891 MT of M&R City Gate	Distribution	Demand/Commodity from related plant	S09 Sum of Meas & Reg Station - City Gate Plant in Service
17	892 MT of Services	Distribution	Customer from related plant	S20 Sum of Services Plant in Services
18	893 MT of Meters & Hs Reg	Distribution	Customer from related plant	S07 Sum of Meter and Installation Plant in Service
19	894 MT of Other Equipment	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
	Customer Accounting Expenses			
20	901 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
21	902 Meter Reading	Customer Relations	Customer	C01 All customers (unweighted)
22	903 Customer Records & Collections	Customer Relations	Customer	C01 All customers (unweighted)
23	904 Uncollectible Accounts	Revenue Conversion	Revenue	R03 Retail Sales Revenue
24	905 Misc Cust Accounts	Customer Relations	Customer	C01 All customers (unweighted)
	Customer Service & Info Expenses			
25	907 Supervision	Customer Relations	Customer	C01 All customers (unweighted)
26	908 Customer Assistance	Customer Relations	Customer	C01 All customers (unweighted)
27	908 DSM Amortization	Distribution	Demand/Commodity by Peak & Average	D01/E01 Coincident peak (all), annual throughput (all)
28	909 Advertising	Customer Relations	Customer	C01 All customers (unweighted)
29	910 Misc Cust Service & Info	Customer Relations	Customer	C01 All customers (unweighted)
	Sales Expenses			
30	911 - 916 Sales Expenses	Customer Relations	Customer	C01 All customers (unweighted)

IPUC Case No. AVU-G-10-01 Methodology Matrix
Avista Utilities Idaho Jurisdiction
Natural Gas Cost of Service Methodology

Line	Account	Functional Category	Classification	Allocation
	Admin & General Expenses			
1	920 Salaries	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
2	921 Office Supplies	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
3	922 Admin Expense Transferred - Credi	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
4	923 Outside Services	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
5	924 Property Insurance	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
6	925 Injuries & Damages	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
7	926 Pensions & Benefits	Common	Demand/Commodity/Customer from Labpr O&M	S13 O&M Labor Expense
8	927 Franchise Requirements	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
9	928 Regulatory Commision	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
10	928 Commission Fees	Revenue Conversion	Revenue	R01 Retail Sales Revenue
11	930 Miscellaneous General	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
12	931 Rents	Common	Demand/Commodity/Customer from Other O&M	S02/E01 50% O&M excl Gas Purchases and A&G / 50% throughput
13	935 MT of General Plant	Common	Demand/Commodity/Customer from Plant in Service	S17 Sum of Total Plant in Service
	Depreciation Expense			
14	Underground Storage	Underground Storage	Commodity same as related plant	Allocations linked to related plant accounts
15	Distribution	Distribution	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
16	General	Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
17	Intangible	Distribution/Common	Demand/Commodity/Customer same as related plant	Allocations linked to related plant accounts
	Taxes			
18	Property Tax	All	Demand/Commodity/Customer from related plant	S14/S15/S16 Sum of UG Plant/Sum of Dist Plant/Sum of Gen Plant
19	Miscellaneous Dist Tax	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
20	State Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
21	Federal Income Tax	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
22	Deferred FIT	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
23	ITC	Revenue Conversion	Revenue	R02 Net Income before Taxes less Interest Expense
	Operating Revenues			
24	Revenue from Rates	Revenue	Revenue	Pro Forma Revenue per Revenue Study
25	Special Contract Revenue	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
26	Off System Sales	Production	Commodity from PGA Tracker	E04 Sales Therms
27	Miscellaneous Service Revenue	Distribution	Demand/Commodity/Customer from Dist Plant	S15 Sum of Distribution Plant in Service
28	Rent From Gas Property	All	Demand/Commodity/Customer from Rate Base	S01 Sum of Rate Base
29	Other Gas Revenue	Underground Storage	Commodity from Underground Storage Plant	S14 Sum of Underground Storage Plant in Service

Sumcost
Company Base Case
AVU-G-04-01 Method

AVISTA UTILITIES
Cost of Service General Summary
For the Year Ended December 31, 2009

Natural Gas Utility
Idaho Jurisdiction

15-Mar-10

	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
Line	Description				System Total	Residential Service Sch 101	Large Firm Service Sch 111	Interrupt Service Sch 131	Transport Service Sch 146
	Plant In Service								
1	Production Plant								
2	Underground Storage Plant				9,012,000	6,697,142	2,019,026	38,802	257,030
3	Distribution Plant				145,902,000	123,149,194	21,127,047	356,203	1,269,555
4	Intangible Plant				2,070,000	1,736,108	308,445	5,258	20,189
5	General Plant				14,846,000	12,443,670	2,218,177	37,855	146,299
6	Total Plant In Service				171,830,000	144,026,114	25,672,694	438,118	1,693,073
	Accum Depreciation								
7	Production Plant								
8	Underground Storage Plant				(3,522,000)	(2,617,325)	(789,060)	(15,164)	(100,451)
9	Distribution Plant				(50,348,000)	(43,188,768)	(6,646,574)	(111,165)	(401,492)
10	Intangible Plant				(953,000)	(798,959)	(142,256)	(2,427)	(9,358)
11	General Plant				(4,703,000)	(3,941,976)	(702,687)	(11,992)	(46,345)
12	Total Accumulated Depreciation				(59,526,000)	(50,547,029)	(8,280,577)	(140,748)	(557,646)
13	Net Plant				112,304,000	93,479,086	17,392,117	297,370	1,135,427
14	Accumlulated Deferred FIT				(20,027,000)	(16,786,423)	(2,992,184)	(51,063)	(197,330)
15	Miscellaneous Rate Base				9,092,000	6,894,202	1,929,679	36,573	231,546
16	Total Rate Base				101,369,000	83,586,865	16,329,612	282,880	1,169,643
17	Revenue From Retail Rates				70,695,000	54,454,987	15,559,532	285,437	395,044
18	Other Operating Revenues				135,000	111,630	21,487	371	1,512
19	Total Revenues				70,830,000	54,566,617	15,581,019	285,808	396,556
	Operating Expenses								
20	Purchased Gas Costs				43,739,000	32,350,162	11,167,655	216,750	4,433
21	Underground Storage Expenses				218,000	162,004	48,840	939	6,218
22	Distribution Expenses				3,767,000	3,187,444	517,030	6,392	56,134
23	Customer Accounting Expenses				2,147,000	2,046,741	96,933	1,337	1,990
24	Customer Information Expenses				242,000	214,749	23,478	425	3,348
25	Sales Expenses				190,000	187,330	2,649	3	18
26	Admin & General Expenses				5,083,000	4,066,188	879,177	17,415	120,220
27	Total O&M Expenses				55,386,000	42,214,618	12,735,761	243,261	192,360
28	Taxes Other Than Income Taxes				922,000	771,509	138,775	2,375	9,340
29	Depreciation Expense								
30	Underground Storage Plant Depr				163,000	121,131	36,518	702	4,649
31	Distribution Plant Depreciation				3,457,000	2,989,983	433,214	6,457	27,346
32	General Plant Depreciation				944,000	791,245	141,045	2,407	9,303
33	Amortization of Intangible Plant				369,000	309,313	55,115	940	3,632
34	Total Depr & Amort Expense				4,933,000	4,211,672	665,893	10,506	44,929
35	Income Tax				2,562,000	1,878,721	628,231	8,413	46,635
36	Total Operating Expenses				63,803,000	49,076,521	14,168,661	264,555	293,264
37	Net Income				7,027,000	5,490,096	1,412,358	21,253	103,292
38	Rate of Return				6.93%	6.57%	8.65%	7.51%	8.83%
39	Return Ratio				1.00	0.95	1.25	1.08	1.27
40	Interest Expense				3,694,000	3,045,999	595,069	10,308	42,623

Sumcost
Company Base Case
AVU-G-04-01 Method

AVISTA UTILITIES
Summary by Function with Margin Analysis
For the Year Ended December 31, 2009

Natural Gas Utility
Idaho Jurisdiction

15-Mar-10

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Functional Cost Components at Current Rates								
1	Production				44,016,692	32,555,548	11,238,557	218,126	4,461
2	Underground Storage				1,594,691	1,101,480	430,124	7,238	55,848
3	Distribution				17,722,200	14,868,955	2,629,089	36,703	187,453
4	Common				7,361,417	5,929,004	1,261,762	23,370	147,281
5	**Total Current Rate Revenue**				**70,695,000**	**54,454,987**	**15,559,532**	**285,437**	**395,044**
6	Exclude Cost of Gas w / Revenue Exp.				43,604,089	32,253,929	11,134,434	215,725	0
7	**Total Margin Revenue at Current Rates**				**27,090,911**	**22,201,058**	**4,425,098**	**69,711**	**395,044**
	Margin per Therm at Current Rates								
8	Production				$0.00532	$0.00550	$0.00550	$0.00550	$0.00134
9	Underground Storage				$0.02056	$0.02008	$0.02271	$0.01657	$0.01681
10	Distribution				$0.22853	$0.27106	$0.13884	$0.08405	$0.05642
11	Common				$0.09492	$0.10809	$0.06663	$0.05352	$0.04433
12	Total Current Margin Melded Rate per Therm				**$0.34933**	**$0.40473**	**$0.23368**	**$0.15965**	**$0.11891**
	Functional Cost Components at Uniform Current Return								
13	Production				44,016,692	32,555,548	11,238,557	218,126	4,461
14	Underground Storage				1,558,757	1,158,368	349,220	6,711	44,457
15	Distribution				17,752,704	15,295,071	2,260,146	34,588	162,899
16	Common				7,366,847	5,987,497	1,212,572	23,086	143,693
17	Total Uniform Current Cost				**70,695,000**	**54,996,485**	**15,060,494**	**282,511**	**355,510**
18	Exclude Cost of Gas w / Revenue Exp.				43,604,089	32,253,929	11,134,434	215,725	0
19	Total Uniform Current Margin				**27,090,911**	**22,742,555**	**3,926,060**	**66,786**	**355,510**
	Margin per Therm at Uniform Current Return								
20	Production				$0.00532	$0.00550	$0.00550	$0.00550	$0.00134
21	Underground Storage				$0.02010	$0.02112	$0.01844	$0.01537	$0.01338
22	Distribution				$0.22892	$0.27883	$0.11935	$0.07921	$0.04903
23	Common				$0.09499	$0.10915	$0.06403	$0.05287	$0.04325
24	Total Current Uniform Margin Melded Rate per				**$0.34933**	**$0.41460**	**$0.20733**	**$0.15295**	**$0.10701**
25	**Margin to Cost Ratio at Current Rates**				**1.00**	**0.98**	**1.13**	**1.04**	**1.11**
	Functional Cost Components at Proposed Rates								
26	Production				44,016,544	32,555,438	11,238,519	218,126	4,461
27	Underground Storage				1,875,805	1,354,429	455,201	8,227	57,949
28	Distribution				19,739,726	16,763,625	2,743,439	40,681	191,980
29	Common				7,637,925	6,189,073	1,277,005	23,904	147,943
30	**Total Proposed Rate Revenue**				**73,270,000**	**56,862,565**	**15,714,164**	**290,938**	**402,333**
31	Exclude Cost of Gas w / Revenue Exp.				43,603,942	32,253,821	11,134,397	215,725	0
32	**Total Margin Revenue at Proposed Rates**				**29,666,058**	**24,608,744**	**4,579,767**	**75,214**	**402,333**
	Margin per Therm at Proposed Rates								
33	Production				$0.00532	$0.00550	$0.00550	$0.00550	$0.00134
34	Underground Storage				$0.02419	$0.02469	$0.02404	$0.01884	$0.01744
35	Distribution				$0.25454	$0.30560	$0.14488	$0.09317	$0.05779
36	Common				$0.09849	$0.11283	$0.06744	$0.05474	$0.04453
37	Total Proposed Margin Melded Rate per Therm				**$0.38254**	**$0.44862**	**$0.24185**	**$0.17225**	**$0.12110**
	Functional Cost Components at Uniform Proposed Return								
38	Production				44,016,544	32,555,438	11,238,519	218,126	4,461
39	Underground Storage				1,858,949	1,381,452	416,474	8,004	53,019
40	Distribution				19,754,017	16,966,041	2,566,838	39,784	181,353
41	Common				7,640,491	6,216,859	1,253,459	23,783	146,390
42	Total Uniform Proposed Cost				**73,270,000**	**57,119,790**	**15,475,290**	**289,697**	**385,223**
43	Exclude Cost of Gas w / Revenue Exp.				43,603,942	32,253,821	11,134,397	215,725	0
44	Total Uniform Proposed Margin				**29,666,058**	**24,865,969**	**4,340,894**	**73,972**	**385,223**
	Margin per Therm at Uniform Proposed Return								
45	Production				$0.00532	$0.00550	$0.00550	$0.00550	$0.00134
46	Underground Storage				$0.02397	$0.02518	$0.02199	$0.01833	$0.01596
47	Distribution				$0.25473	$0.30929	$0.13555	$0.09111	$0.05459
48	Common				$0.09852	$0.11333	$0.06619	$0.05447	$0.04406
49	Total Proposed Uniform Margin Melded Rate p				**$0.38254**	**$0.45331**	**$0.22923**	**$0.16941**	**$0.11595**
50	**Margin to Cost Ratio at Proposed Rates**				**1.00**	**0.99**	**1.06**	**1.02**	**1.04**
51	**Current Margin to Proposed Cost Ratio**				**0.91**	**0.89**	**1.02**	**0.94**	**1.03**

Sumcost	AVISTA UTILITIES	Natural Gas Utility	15-Mar-10
Company Base Case	Summary by Classification with Unit Cost Analysis	Idaho Jurisdiction	
AVU-G-04-01 Method	For the Year Ended December 31, 2009		

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Cost by Classification at Current Return by Schedule								
1	Commodity				44,593,359	32,629,500	11,474,728	259,571	229,561
2	Demand				13,596,731	10,163,928	3,317,232	24,700	90,871
3	Customer				12,504,910	11,661,559	767,572	1,166	74,612
4	Total Current Rate Revenue				70,695,000	54,454,987	15,559,532	285,437	395,044
	Revenue per Therm at Current Rates								
5	Commodity				$0.57503	$0.59484	$0.60596	$0.59445	$0.06910
6	Demand				$0.17533	$0.18529	$0.17518	$0.05657	$0.02735
7	Customer				$0.16125	$0.21259	$0.04053	$0.00267	$0.02246
8	Total Revenue per Therm at Current Rates				$0.91161	$0.99272	$0.82167	$0.65369	$0.11891
	Cost per Unit at Current Rates								
9	Commodity Cost per Therm				$0.57503	$0.59484	$0.60596	$0.59445	$0.06910
10	Demand Cost per Peak Day Therms				$21.55	$20.89	$26.67	$11.32	$5.14
11	Customer Cost per Customer per Month				$14.18	$13.42	$62.45	$97.16	$888.24
	Cost by Classification at Uniform Current Return								
12	Commodity				44,492,354	32,772,272	11,254,586	257,964	207,532
13	Demand				13,546,115	10,340,188	3,104,716	23,428	77,783
14	Customer				12,656,531	11,884,025	701,192	1,119	70,195
15	Total Uniform Current Cost				70,695,000	54,996,485	15,060,494	282,511	355,510
	Cost per Therm at Current Return								
16	Commodity				$0.57373	$0.59744	$0.59433	$0.59077	$0.06247
17	Demand				$0.17468	$0.18850	$0.16395	$0.05365	$0.02341
18	Customer				$0.16320	$0.21665	$0.03703	$0.00256	$0.02113
19	Total Cost per Therm at Current Return				$0.91161	$1.00259	$0.79532	$0.64699	$0.10701
	Cost per Unit at Uniform Current Return								
20	Commodity Cost per Therm				$0.57373	$0.59744	$0.59433	$0.59077	$0.06247
21	Demand Cost per Peak Day Therms				$21.47	$21.25	$24.96	$10.74	$4.40
22	Customer Cost per Customer per Month				$14.36	$13.67	$57.05	$93.25	$835.65
23	**Revenue to Cost Ratio at Current Rates**				1.00	0.99	1.03	1.01	1.11
	Cost by Classification at Proposed Return by Schedule								
24	Commodity				45,303,364	33,264,224	11,542,926	262,593	233,622
25	Demand				14,451,098	10,947,630	3,383,093	27,091	93,284
26	Customer				13,515,538	12,650,712	788,145	1,254	75,427
27	Total Proposed Rate Revenue				73,270,000	56,862,565	15,714,164	290,938	402,333
	Revenue per Therm at Proposed Rates								
28	Commodity				$0.58418	$0.60641	$0.60956	$0.60137	$0.07032
29	Demand				$0.18635	$0.19958	$0.17866	$0.06204	$0.02808
30	Customer				$0.17428	$0.23062	$0.04162	$0.00287	$0.02270
31	Total Revenue per Therm at Proposed Rates				$0.94481	$1.03661	$0.82984	$0.66629	$0.12110
	Cost per Unit at Proposed Rates								
32	Commodity Cost per Therm				$0.58418	$0.60641	$0.60956	$0.60137	$0.07032
33	Demand Cost per Peak Day Therms				$22.91	$22.50	$27.20	$12.42	$5.28
34	Customer Cost per Customer per Month				$15.33	$14.55	$64.12	$104.53	$897.94
	Cost by Classification at Uniform Proposed Return								
35	Commodity				45,255,594	33,332,044	11,437,551	261,911	224,088
36	Demand				14,426,897	11,031,358	3,281,369	26,551	87,620
37	Customer				13,587,509	12,756,388	756,371	1,234	73,515
38	Total Uniform Proposed Cost				73,270,000	57,119,790	15,475,290	289,697	385,223
	Cost per Therm at Proposed Return								
39	Commodity				$0.58357	$0.60764	$0.60400	$0.59981	$0.06745
40	Demand				$0.18603	$0.20110	$0.17328	$0.06081	$0.02637
41	Customer				$0.17521	$0.23255	$0.03994	$0.00283	$0.02213
42	Total Cost per Therm at Proposed Return				$0.94481	$1.04129	$0.81722	$0.66344	$0.11595
	Cost per Unit at Uniform Proposed Return								
43	Commodity Cost per Therm				$0.58357	$0.60764	$0.60400	$0.59981	$0.06745
44	Demand Cost per Peak Day Therms				$22.87	$22.67	$26.38	$12.17	$4.96
45	Customer Cost per Customer per Month				$15.41	$14.68	$61.54	$102.87	$875.18
46	**Revenue to Cost Ratio at Proposed Rates**				1.00	1.00	1.02	1.00	1.04
47	**Current Revenue to Proposed Cost Ratio**				0.96	0.95	1.01	0.99	1.03

Sumcost
Company Base Case
AVU-G-04-01 Method

AVISTA UTILITIES
Customer Cost Analysis
For the Year Ended December 31, 2009

Natural Gas Utility
Idaho Jurisdiction

15-Mar-10

Line	(b) Description	(c)	(d)	(e)	(f) System Total	(g) Residential Service Sch 101	(h) Large Firm Service Sch 111	(j) Interrupt Service Sch 131	(k) Transport Service Sch 146
	Meter, Services, Meter Reading & Billing Costs by Schedule at Requested Rate of Return								
	Rate Base								
1	Services				45,320,000	44,664,982	631,586	1,850	21,582
2	Services Accum. Depr.				(20,150,000)	(19,858,768)	(280,813)	(822)	(9,596)
3	Total Services				25,170,000	24,806,213	350,773	1,027	11,986
4	Meters				18,678,000	16,221,340	2,351,127	5,032	100,501
5	Meters Accum. Depr.				(4,476,000)	(3,887,285)	(563,425)	(1,206)	(24,084)
6	Total Meters				14,202,000	12,334,054	1,787,702	3,826	76,417
7	Total Rate Base				39,372,000	37,140,268	2,138,475	4,854	88,403
8	Return on Rate Base @ 8.55%				3,366,306	3,175,493	182,840	415	7,558
9	Revenue Conversion Factor				0.63676	0.63676	0.63676	0.63676	0.63676
10	**Rate Base Revenue Requirement**				**5,286,583**	**4,986,923**	**287,139**	**652**	**11,870**
	Expenses								
11	Services Depr Exp				1,330,000	1,310,777	18,535	54	633
12	Meters Depr Exp				656,000	569,718	82,575	177	3,530
13	Services Maintenance Exp				316,000	311,433	4,404	13	150
14	Meters Maintenance Exp				282,000	244,909	35,497	76	1,517
15	Meter Reading				174,000	171,555	2,426	2	17
16	Billing				1,480,000	1,459,205	20,634	20	141
17	Total Expenses				4,238,000	4,067,598	164,071	342	5,989
18	Revenue Conversion Factor				0.99384	0.99384	0.99384	0.99384	0.99384
19	**Expense Revenue Requirement**				**4,264,268**	**4,092,810**	**165,088**	**345**	**6,026**
20	**Total Meter, Service, Meter Reading, and**				**9,550,851**	**9,079,732**	**452,227**	**996**	**17,896**
21	Total Customer Bills				881,591	869,204	12,291	12	84
22	**Average Unit Cost per Month**				**$10.83**	**$10.45**	**$36.79**	**$83.02**	**$213.05**
	Fixed Costs per Customer								
23	Total Customer Related Cost				13,587,509	12,756,388	756,371	1,234	73,515
24	Customer Related Unit Cost per Month				$15.41	$14.68	$61.54	$102.87	$875.18
25	Other Non-Gas Costs				16,078,549	12,109,581	3,584,522	72,738	311,708
26	Other Non-Gas Unit Cost per Month				$18.24	$13.93	$291.64	$6,061.48	$3,710.81
27	**Total Fixed Unit Cost per Month**				**$33.65**	**$28.61**	**$353.18**	**$6,164.34**	**$4,585.99**