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Appendix A–Sales and Load Forecast
For the 2006 Integrated Resource Plan

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INTRODUCTION

Idaho Power Company (Idaho Power or the Company) has prepared the 2006 Sales and Load Forecast as an appendix to its 2006 Integrated Resource Plan (IRP). The Sales and Load Forecast presents the Company's best estimate of the future demand for electricity within its service area. The forecast covers the 20-year period from 2006 through 2025. For planning purposes, the future demand for electricity by customers in the Company's service area is represented by three load forecasts: (1) a 50th percentile or expected case load forecast, (2) a 70th percentile load forecast, and (3) a 90th percentile load forecast. These forecasts define three possible load conditions evaluated in the 2006 IRP. The expected case total load growth rate is 1.8 percent per year over the 20-year planning period. This is Idaho Power's estimate of the most probable outcome for load growth during the planning period and is based on the most recent economic forecast for the Company's service area.

Two additional load forecasts for the Idaho Power service area were prepared that provide a range of possible load growths for the 2006–2025 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based upon statistical analysis to empirically reflect uncertainty inherent in the load forecast.

The expected case load forecast assumes median temperatures and median rainfall. Since actual loads can vary significantly dependent upon weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70th percentile load forecast and a 90th percentile load forecast were prepared to illustrate the weather-related uncertainty inherent in forecasting electrical loads. The 70th percentile load forecast assumes monthly loads that can be exceeded in 3 out of 10 years (30 percent of the time). The 90th percentile load forecast assumes monthly loads that can be exceeded in 1 out of 10 years (10 percent of the time).

In the expected case scenario, total company load is forecast to increase to 2,464 average megawatts in the year 2025 from the 2006 forecast load of 1,746 average megawatts. The expected case forecast total load growth rate averages 1.8 percent per year over the 20 years of the planning period (2006–2025). The number of Idaho Power retail customers increased from the December 2005 level of 455,527 customers to about 683,362 customers at year-end 2025. The Company system peak load is forecast to grow to 4,627 megawatts in the year 2025 from the 2005 actual system peak of 2,961 megawatts. The highest system peak on record was 3,084 megawatts and occurred on Monday, July 24, 2006 at 6:00 p.m. In the expected case scenario, the Company system peak increases at an average growth rate of 2.1 percent per year over the 20 years of the planning period (2006–2025).

This Sales and Load Forecast is strongly influenced by the 2006 Economic Forecast developed by an independent consultant, John Church of Idaho Economics. The 2006 Economic Forecast is based on a forecast of national and regional economic activity performed by Global Insight, a national econometric consulting firm. The Global Insight economic forecast is modified by Idaho Economics to reflect anticipated service area conditions.

Economic growth assumptions influence several of the individual class of service growth rates. Economic growth information for Idaho and its counties can be found in *Appendix C–Economic Forecast*. The number of households in the state of Idaho is projected to grow at an annual average rate of 1.7 percent during the forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area households are derived from county-specific household

forecasts. The number of households and employment projections, along with customer consumption patterns, are each used to form load projections.

In addition to the economic assumptions used to drive the expected case forecast scenario, several specific assumptions were incorporated in the forecasts of the individual sectors. Further discussion of these assumptions is presented in the sections of this report pertaining to these individual sectors.

The future load impacts of implemented and committed Idaho Power Demand-Side Management (DSM) programs are considered within the 2006 Sales and Load Forecast. These programs and their expected impacts are addressed in more detail in the Company's *Demand-Side Management 2005 Annual Report*. This report is Appendix B to the 2006 IRP.

The expected case load forecast represents Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future electricity sales will not follow exactly the path suggested by the expected case load forecast. Therefore, four additional load forecasts were prepared, two that provide a range of possible load growths due to economic uncertainty, and two that address the load variability associated with abnormal weather. The "high growth" and "low growth" scenarios provide boundaries on each side of the expected case scenario and reflect economic uncertainty. The 70th percentile and 90th percentile load forecast scenarios were developed to assist the Company in reviewing the resource requirements that would result from higher loads due to more adverse weather.

Several changes in rate structure that were not considered in the development of the 2006 Sales and Load Forecast were seasonal rates, time-of-use rates, and block rates that were each implemented in June of 2004. The impacts of these changes to rate structure on the Sales and Load Forecast will be considered as more time-series data is collected.

During the 20-year forecast horizon there could be major changes in the electric utility industry. However, the implications of any major changes are unknown at this time and are not reflected in this forecast. The alternative sales and load scenarios of the 2006 Sales and Load Forecast were prepared under the assumption that Idaho Power will continue to serve all customers in its franchised service area during the planning period.

Data describing the historical and projected figures for sales and load is found in Appendix A1 of this report.

2006 IRP VERSUS 2004 IRP

Average Load Comparisons

The 2006 IRP average system load forecast is lower than the 2004 IRP average system load forecast. A return to lower, more normal retail electricity prices and higher than expected residential customer growth combined to end the pause in load growth that occurred over the 2001–2004 period. The reduction in retail electricity prices and the recovery in the service area economy caused load growth to return, although at a somewhat slower pace than before and starting at a lower level than previously forecast in the 2004 IRP. Significant factors that influenced the outcome of the 2006 IRP load forecast include:

- Regaining strength in the service area economy experienced in the past few years.
- A faster growth in the number of service area households as forecast by Idaho Economics.

- Higher residential sales forecast due to a significant increase in the number of new service area households.

- Commercial, irrigation, and industrial load forecasts each lower than forecasts made for the 2004 IRP.

- The loss of the Company's largest irrigation customer, Bell Rapids, due to the purchase of its water rights by the State of Idaho.

- Higher retail electricity prices expected throughout forecast period, mostly the result of new generation additions.

- Slower growth at Micron Technology than assumed in the 2004 IRP.

- The long-term firm sales contract with the City of Weiser is assumed to expire December 31, 2006, and will not be renewed.

- A change to a 20-year planning period.

Peak Hour Comparisons

Peak-day temperatures and the growth in average loads drive the peak forecasting model regressions. The lower average load forecast in the 2006 IRP resulted, in most cases, in lower monthly peak forecast figures. However, the peak forecast results and comparisons with the 2004 IRP differ for a number of reasons that include:

- The update of the 12 monthly peak model regressions using MetrixND (statistical software from RER, an Itron Company).

- The loss of the Company's largest irrigation customer, Bell Rapids, resulted in a peak reduction of 20–25 megawatts in June and July of each year.

- This 2006 IRP peak demand forecast was adjusted downward to reflect the estimated impact of the DSM programs that were selected for implementation since 2004.

- The modeling procedure in the 2006 IRP peak model was carefully reviewed and logic changes were made to more accurately forecast the peaks at various percentiles of temperatures.

- The peak model allows peaks to be calculated at 0, 10^{th}, 20^{th}, 30^{th}, 40^{th}, 50^{th}, 60^{th}, 70^{th}, 80^{th}, 90^{th}, 95^{th}, and 100^{th} percentiles of peak-day temperatures for each month of the year.

- The addition of more recent historical peak data to the peak model regressions. The July 2002, July 2003, June 2005, and July 2005 peak-day temperatures were near the 100^{th} percentile and their addition to the regression models impacted forecast results.

- The summer peak regression models do not use the 2001 firm peak data as the 2001 voluntary load reduction program, which paid irrigators not to use electricity, impacted the 2001 peaks.

- The Company continues to utilize a median peak-day temperature driver in lieu of an average peak-day temperature driver. The median peak-day temperature has a 50 percent probability of being exceeded. Peak-day temperatures are not normally distributed and can be skewed by one or more extreme observations; therefore the median temperature better reflects expected temperatures.

Overview of the Forecast

The sales and load forecast is constructed by developing a separate forecast for each individual sales category. Independent sales

forecasts are prepared for each of the major customer classes: residential, commercial, irrigation, and industrial. Individual energy and peak demand forecasts are developed for Micron Technology, Simplot Fertilizer Company, Idaho National Laboratory (INL), the City of Weiser, and Raft River Rural Electric Cooperative, Inc. (the electric distribution utility serving Idaho Power Company's former customers in the state of Nevada). These five special contract customers are combined into a single forecast category labeled Additional Firm Load. Lastly, the contract off-system category represents long-term contracts to supply firm energy and demand to off-system customers. The assumptions for each of the individual categories are described in greater detail in their respective sections.

Since the residential, commercial, irrigation, and industrial sales forecasts provide a forecast of sales as they are billed, it is necessary to adjust these billed sales to the proper timeframe to reflect the required generation needed in each calendar month. To determine calendar-month sales from billed sales, the billed sales must first be allocated to the calendar months in which they are generated. The calendar-month sales are then converted to calendar-month load by adding losses and dividing by the number of hours each month.

Loss factors are determined by Idaho Power's Distribution Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load including losses.

The peak load forecast was prepared in conjunction with the 2006 sales forecast. Idaho Power has two distinct peak periods: a winter peak resulting from space heating demand that normally occurs in December, January, or February, and a larger summer peak that normally occurs in June or July. The summer peak generally occurs when extensive air conditioning usage coincides with significant irrigation demand.

Peak loads are forecast via 12 regression equations and are a function of temperature, space heating saturation (winter only), air conditioning saturation (summer only), historical average load, and precipitation (summer only). The peak forecast utilizes statistically derived peak-day temperatures based on 30 or more years of climate data for each month. Peak loads for the INL, Micron Technology, Simplot Fertilizer, the City of Weiser, Raft River Rural Electric Cooperative, Inc., and the firm off-system contracts are forecast based on historical analysis and contractual considerations.

The primary exogenous factors in the forecast are macroeconomic and demographic data. Global Insight provides the macroeconomic forecasts. The national econometric projections are tailored to Idaho Power's service area by an independent consultant, John Church of Idaho Economics. Specific demographic projections are also developed for the service area from national and local census data.

Fuel Prices

Fuel prices, in combination with service area economic data, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. Global Insight provides the forecasts of long-term changes in nominal natural gas prices. The nominal price estimates are adjusted for projected inflation by applying the appropriate economic deflators to arrive at real fuel prices. The projected average annual growth rates of fuel prices in nominal and real terms (adjusted for inflation) are presented in Table 1. The growth rates shown are for residential fuel prices and can be used as a proxy for fuel price growth rates in the commercial, industrial, and irrigation sectors.

Figure 1 illustrates the average electricity price (in cents per kWh) paid by Idaho Power's residential customers over the historical period 1973–2005 and over the forecast period 2006–2025. Both nominal and real prices are shown. Nominal electricity prices are expected to slowly climb to over nine cents per kWh by the end of the forecast period in 2025. Real electricity prices (inflation-adjusted) are expected to decline over the forecast period at an average rate of 0.1 percent each year.

Table 1. Residential Fuel Price Escalation, 2005–2025
(average annual percent change)

	Nominal	Real*
Electricity	2.0%	-0.1%
Natural Gas	0.0%	-2.1%

*adjusted for inflation

Electricity prices for Idaho Power customers were significantly higher in 2001, 2002, and 2003 because of the Power Cost Adjustment impact on rates. Except for those three years, Idaho Power's electricity prices have been historically quite stable. Over the 1990–2000 period, electricity prices rose only eight percent overall, an annual average compound growth rate of 0.8 percent each year. In June 2003, electricity prices for Idaho Power customers returned to levels much closer to normal, between five and a half and six cents per kWh for residential customers.

Figure 2 illustrates the average natural gas price (in dollars per therm) paid by Intermountain Gas Company's residential customers over the historical period 1973–2005. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since 2001, natural gas prices moved downward for a couple of years before again moving sharply upward in 2004 and 2005. Natural gas prices are expected to move upward again in 2006 to a price level twice as high as the prices experienced throughout the 1990s. After peaking in 2006, nominal natural gas prices are expected to trend lower over the five years that follow. Natural gas prices at the end of the forecast period are expected to nearly match the prices in 2005, growing at an average rate of zero percent per year over the forecast period (2005–2025). Real natural gas prices (adjusted for inflation) are expected to decline over the same period at an average rate of 2.1 percent each year.

If natural gas prices continue to outpace electricity prices, as they have over the past several years, at some point the operating costs

Figure 1. Forecasted Electricity Prices
(cents per kWh)

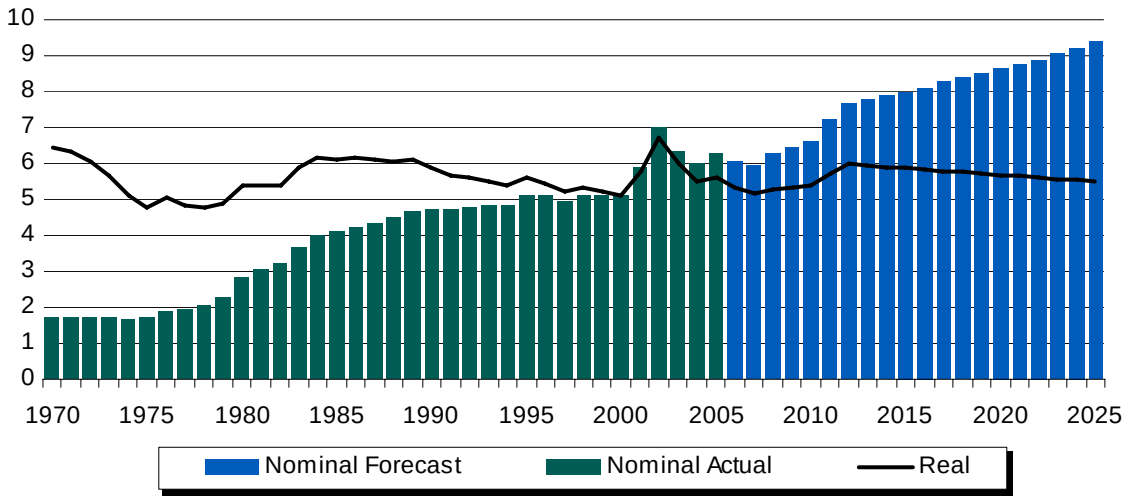
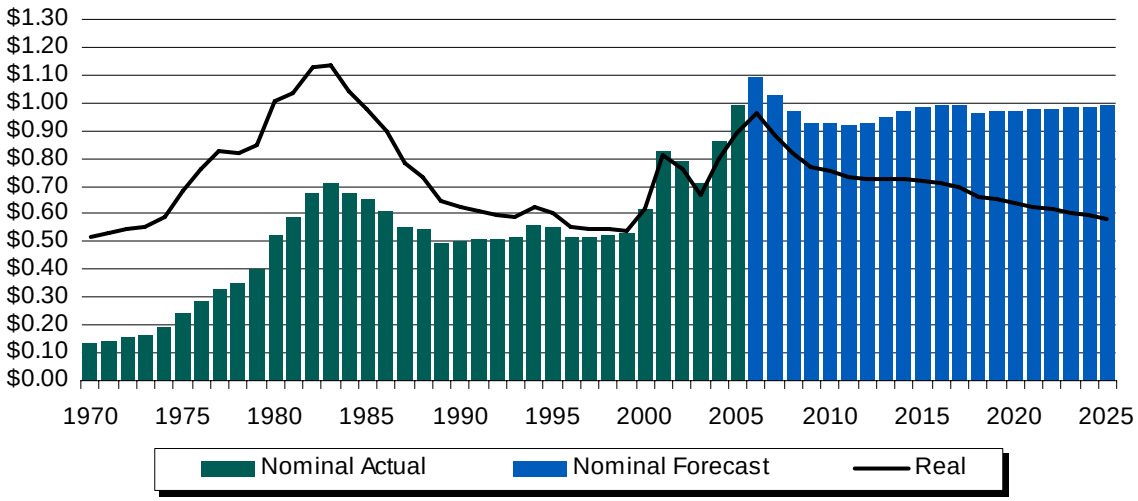


Figure 2. Forecasted Natural Gas Prices
(dollars per therm)



of space heating and water heating homes with electricity will become comparable with that of natural gas. Eventual price parity could have a significant impact on future electricity demands, especially in the wintertime.

Forecast Probabilities

Load Forecasts Based on Weather Variability

The future demand for electricity by customers in Idaho Power's service area is represented by three load forecasts reflecting a range of load uncertainty due to weather. The expected case load forecast represents the most probable projection of system load growth during the planning period and is based on the most recent economic forecast for the Company's service area.

The expected case load forecast assumes median temperatures and median precipitation, i.e., there is a 50 percent chance that loads will be higher or lower than the expected case loads due to colder-than-median or hotter-than-median temperatures, or wetter-than-median or drier-than-median precipitation. Since actual loads can vary significantly dependant upon weather conditions, two alternative scenarios were considered that address load variability due to weather.

Maximum load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum load occurs when the lowest recorded levels of heating degree days are assumed in winter and the lowest recorded levels of cooling and growing degree days combined with the highest level of precipitation are assumed in summer.

For example, at the Boise Weather Service Office the median HDD in December over the 1948–2005 period was 1,040 HDD. The 70th percentile HDD is 1,069 HDD and would be exceeded in 3 out of 10 years. The 90th percentile HDD is 1,185 HDD and would be exceeded in 1 out of 10 years. The 100th percentile HDD (the coldest December on record) is 1,619 and occurred in December 1985. This same concept was applied in each month throughout the year in only the weather-sensitive customer classes: residential, commercial, and irrigation.

In the 70th percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in wintertime and at the 70th percentile of CDD in summertime. In the 70th percentile irrigation load forecast, GDD were assumed to be at the 70th percentile and precipitation at the 30th percentile reflecting drier-than-median weather. The 90th percentile load forecast was similarly constructed.

Idaho Power loads are highly dependant upon weather and these two scenarios allow us to carefully examine load variability and how it may impact resource requirements. It is important to understand that the probabilities associated with these forecasts apply to any given month. To assume that temperatures and precipitation would maintain a 70th percentile or 90th percentile level continuously month after month throughout the year would be much less probable. It is the monthly forecast numbers that are being evaluated for resource planning, and one must be careful in interpreting the meaning of the annual average load figures being reported and graphed.

Table 2 summarizes the load scenarios prepared for the 2006 IRP. Three average load scenarios were prepared based upon a statistical analysis of historical monthly weather variables listed. The probability associated with each individual average load scenario is also indicated in the table. In addition, three peak demand scenarios were prepared based upon a statistical analysis of historical peak-day temperatures. The probability associated with each individual peak demand scenario is also indicated in Table 2.

The analysis of resource requirements is based on the 70th percentile average load forecast coupled with the 95th percentile peak demand forecast so that a more adverse representation of peak demands would be considered. Otherwise, the expected case (50th percentile) average load forecast and the 90th percentile peak demand forecast were coupled together for consideration.

Load Forecasts Based on Economic Uncertainty

The expected case load forecast is based on the most recent economic forecast for the Company's service area and represents Idaho Power's most probable outcome for load growth during the planning period. Two additional load forecasts for the Idaho Power service area were prepared that provide a range of possible load growths for the 2006–2025 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based upon statistical analysis to empirically reflect uncertainty inherent in the load forecast. The average growth rates for the high and low growth scenarios were derived from the historical distribution of one-year growth rates over the period 1979–2005.

Table 2. Average Load and Peak Demand Forecast Scenarios

Scenario	Weather Probability	Probability of Exceeding	Weather Driver
Forecasts of Average Load			
90th Percentile	90%	1 in 10 years	HDD, CDD, GDD, Precipitation
70th Percentile	70%	3 in 10 years	HDD, CDD, GDD, Precipitation
Expected Case	50%	1 in 2 years	HDD, CDD, GDD, Precipitation
Forecasts of Peak Demand			
95th Percentile	95%	1 in 20 years	Peak-Day Temperatures
90th Percentile	90%	1 in 10 years	Peak-Day Temperatures
50th Percentile	50%	1 in 2 years	Peak-Day Temperatures

The estimated probabilities for the three different load scenarios are reported in Table 2. The probability estimates are calculated using the annual growth rates in weather-adjusted firm sales observed between 1979 and 2005. The standard deviation observed during the historical time period is used to estimate the dispersion around the expected case scenario. The probability estimates assume that the expected forecast is the median growth path, i.e., there is a 50 percent probability that the actual growth rate will be less than the expected case growth rate, and a 50 percent chance that the actual growth rate will be greater than the expected case growth rate. In addition, the probability estimates assume that the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1979–2005).

Two types of probability estimates are reported in Table 3. The first probability, the probability of exceeding, shows the likelihood that the actual load growth will be greater than the projected growth rate in the specified scenario. For example, over the next 20 years there is a 10 percent probability that the actual growth rate will exceed the growth rate projected in the high scenario, and conversely, there is a 10 percent chance that the actual growth rate would fall below that of the low scenario. In other words, over a 20-year time period there is an 80 percent probability that the actual growth rate of firm load will fall between the growth rates projected in the high and low scenarios. The second probability estimate, the probability of occurrence, indicates the likelihood that the actual growth will be closer to the growth rate specified in that scenario than to the growth rate specified in any other scenario. For example, there is a 26 percent probability that the actual growth rate will be closer to the high scenario than to any of the other forecast scenarios for the entire 20-year planning horizon. Probabilities for shorter 1-year, 5-year, and 10-year time periods are also shown in Table 3.

Table 3. Forecast Probabilities

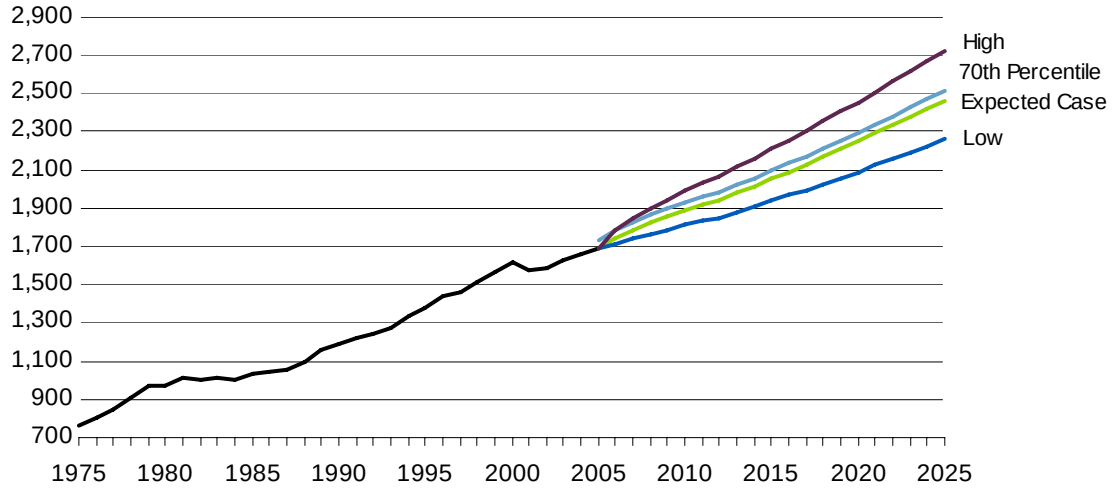
Probability of Exceeding				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth.....	90%	90%	90%	90%
Expected Case.....	50%	50%	50%	50%
High Growth	10%	10%	10%	10%
Probability of Occurrence				
Scenario	**1-year**	**5-year**	**10-year**	**20-year**
Low Growth.....	26%	26%	26%	26%
Expected Case.....	48%	48%	48%	48%
High Growth	26%	26%	26%	26%

Firm load includes the sum of residential, commercial, industrial, irrigation, as well as special contracts (excluding Astaris), the City of Weiser, and Raft River Rural Electric Cooperative, Inc. Company firm load projections are reported in Table 4 and pictured in Figure 3. The expected case firm load forecast growth rate averages 1.9 percent per year over the 20 years of the planning period. The low scenario projects that firm load will increase at an average rate of 1.5 percent per year throughout the forecast period. The high scenario projects load growth of 2.4 percent per year. The Company has experienced both the high and low growth rates in the past. These scenario forecasts provide a range of projected growth rates that cover approximately 80 percent of the probable outcomes as measured by Idaho Power Company's historical experience.

Table 4. Firm Load Growth
(average megawatts)

Growth	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
High.....	1,693	1,993	2,210	2,724	2.4%
Expected	1,693	1,892	2,051	2,464	1.9%
Low	1,693	1,816	1,937	2,261	1.5%

Figure 3. Forecasted Firm Load
(average megawatts)



The remainder of the 2006 Sales and Load Forecast document is organized by individual sectors. All information pertaining to a particular sector can be found under the appropriate heading.

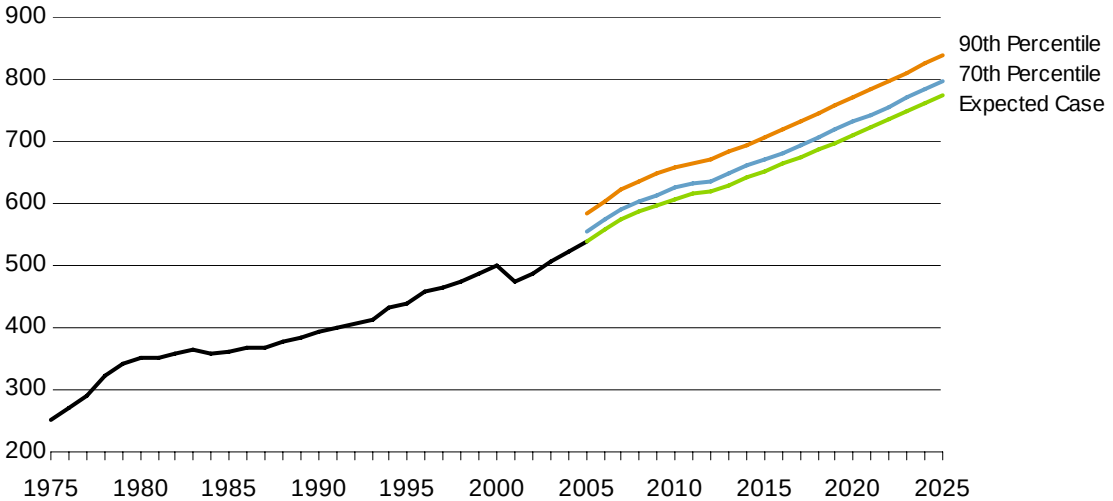
RESIDENTIAL

The expected case residential load is forecast to increase from 539 average megawatts in 2005 to 774 average megawatts in 2025, an average annual compound growth rate of 1.8 percent. In the 70th percentile scenario residential load is forecast to increase from 554 average megawatts in 2005 to 796 average megawatts in 2025, matching the expected case residential growth rate. The residential load forecasts are reported in Table 5 and shown graphically in Figure 4.

Table 5. Residential Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
90th Percentile	584	658	706	838	1.8%
70th Percentile	554	624	670	796	1.8%
Expected Case.....	539	607	651	774	1.8%

Figure 4. Forecasted Residential Load
(average megawatts)



Sales to residential customers made up 24 percent of the Company's system sales in 1970 and 35 percent of system sales in 2005. The residential customer proportion of system sales is forecast to be approximately 34 percent in 2025. There were 380,952 residential customers as of December 2005. The number of residential customers is projected to increase to around 570,676 by December 2025. The relative customer proportions of the total company electricity sales are shown in Figure 19.

The average sales per residential customer were about 10,000 kWh in 1970. Average sales increased to nearly 14,800 kWh per residential customer in 1979 before declining to 13,100 kWh in 2001. In 2002 and 2003 residential use per customer dropped dramatically, about 500 kWh per customer from 2001, the result of two years of significantly higher electricity prices combined with a weak national and service area economy. The reduction in electricity prices in mid-May 2003 and a recovery in the service area economy caused residential use per customer to stabilize through 2005. However, beginning in 2007, residential use per customer is expected to return to a pattern of slow decline. The average sales per residential customer is expected to decline to approximately 12,000 kWh per year in 2025. Average annual sales per residential customer is shown in Figure 5.

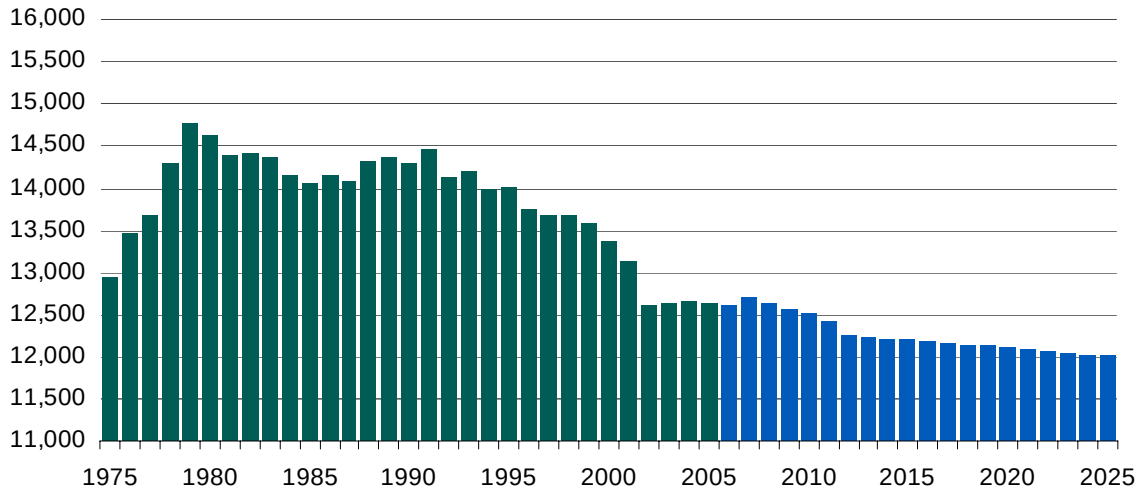
The residential sales forecast is based on a forecast of the number of residential customers and an econometric analysis of residential use per customer. The number of residential customers being added each year is a direct function of the number of new service area households being added each year as provided by the 2006 Economic Forecast. The customer forecast for 2005–2025 shows an average annual growth rate of 2.0 percent.

The residential use per customer estimates consider several factors affecting electricity sales to residential customers. Residential use per customer is a function of HDD (wintertime), CDD (summertime), use per customer trends, and the price of electricity. The resulting forecast of residential use per customer is multiplied by the residential customer forecast to obtain the residential energy forecast.

COMMERCIAL

The commercial category is primarily made up of Idaho Power Company's Small General Service and Large General Service customers. Other schedules that are considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn Customer Lighting.

Figure 5. Forecasted Residential Use Per Customer
(weather-adjusted kWh)



In the expected case scenario, commercial load is projected to increase from 414 average megawatts in 2005 to 698 average megawatts in 2025. The average annual compound growth rate of commercial load is 2.6 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 419 average megawatts in 2005 to 705 average megawatts in 2025. The commercial load forecasts are illustrated in Figure 6.

Table 6. Commercial Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
90th Percentile	428	506	568	720	2.6%
70th Percentile	419	496	556	705	2.6%
Expected Case	414	491	551	698	2.6%

As of December 2005, there were about 58,087 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2.3 percent, reaching 91,114 customers in 2025. Commercial customers consumed nearly 17 percent of the Company's system sales in 1970 and 27 percent of system sales in 2005. The commercial customer proportion of system sales is projected to increase to nearly 31 percent of system sales by 2025. The relative customer proportions of the Company's total electricity sales are shown in Figure 19.

The average consumption per commercial customer increased to a record 67,333 kWh in 2001. However, two years of significantly higher electricity prices combined with a weak national and service area economy caused a setback in the growth of commercial use per customer beginning in 2002. The reduction in electricity prices in mid-May 2003 and a slow recovery in the service area economy slowed the rate of decline in commercial use per customer through 2005. Beginning in 2006, commercial use per customer is expected to return to an upward growth pattern, although at a slower pace than before and starting at a lower level. The average consumption per commercial customer is expected to increase to approximately 68,000 kWh per customer in 2025. Average annual use per commercial customer is pictured in Figure 7.

The commercial sales forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial use per customer. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. The number of

Figure 6. Forecasted Commercial Load
(average megawatts)

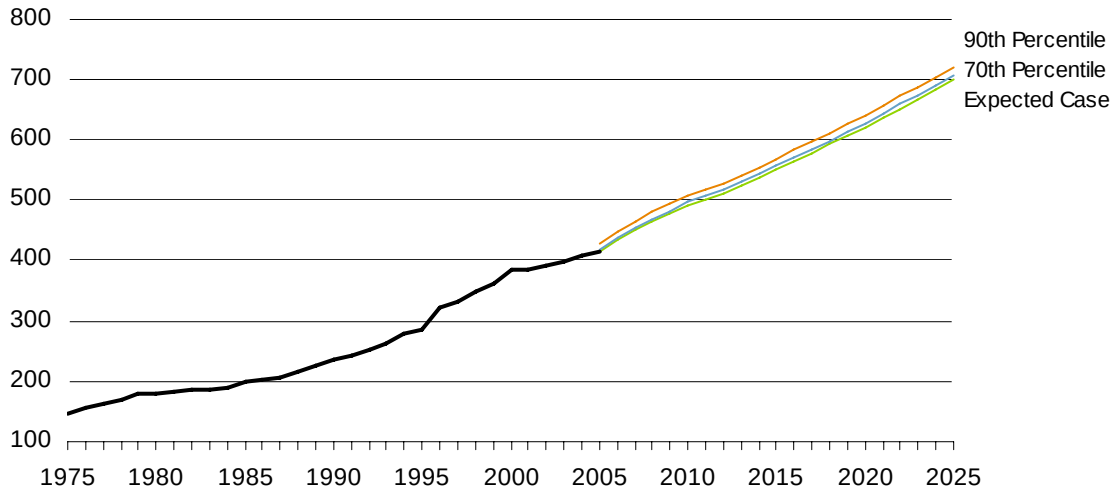
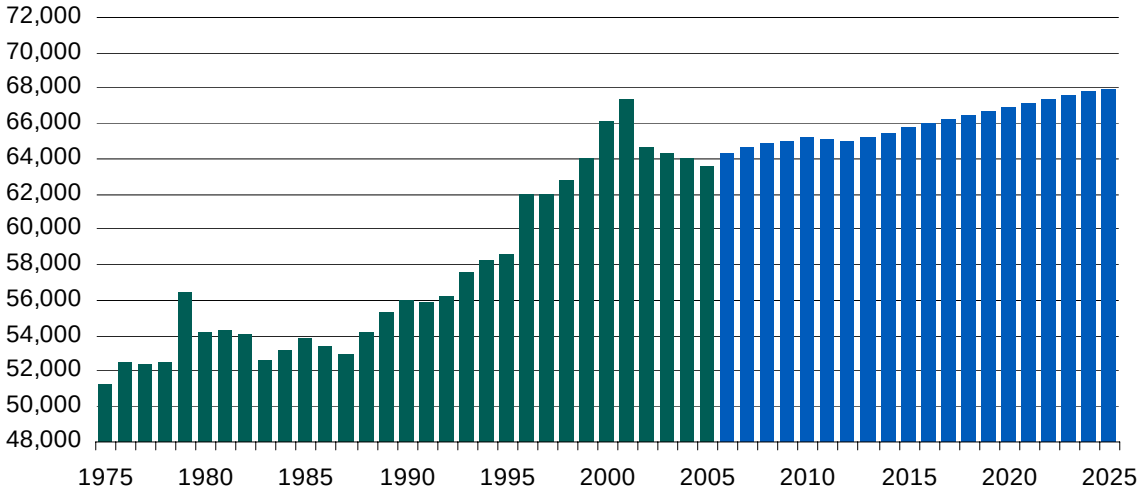


Figure 7. Forecasted Commercial Use Per Customer
(weather-adjusted kWh)



residential customers being added is a direct function of the number of new service area households as provided by the 2006 Economic Forecast. The commercial customer forecast for 2005–2025 shows an average annual growth rate of 2.3 percent.

The commercial use per customer equation considers several factors affecting electricity sales to commercial customers. Commercial use per customer is a function of HDD (wintertime), CDD (summertime), use per customer trends, and electricity prices. The forecast of commercial use per customer is multiplied by the commercial customer forecast to obtain the commercial energy forecast.

IRRIGATION

The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural use customers at one point-of-delivery for operating water pumping or water delivery systems to irrigate agricultural crops or pasturage.

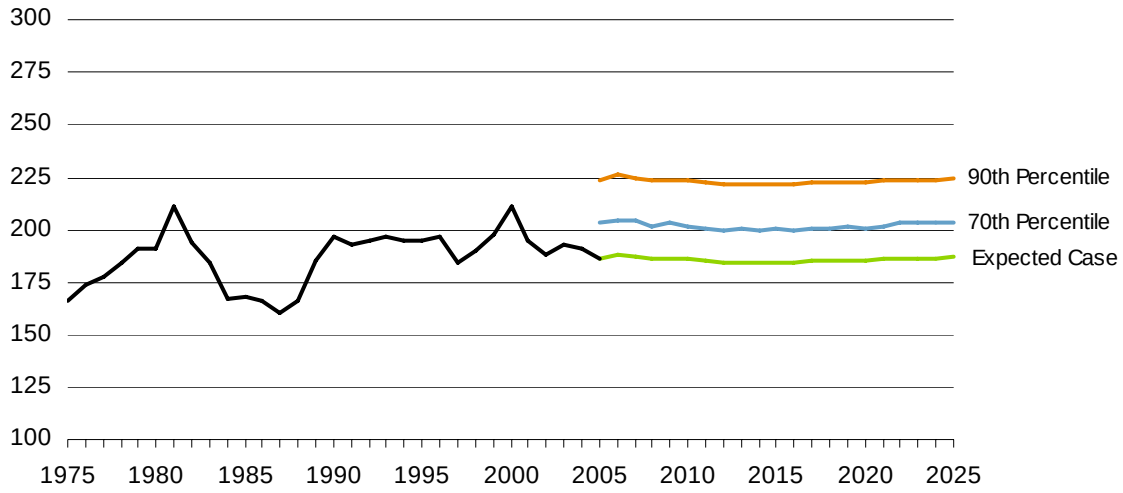
The expected case irrigation load is forecast to increase hardly at all, from 186 average megawatts in 2005 to 187 average megawatts in 2025, an average annual compound growth rate of zero percent. The expected case, 70th percentile, and 90th percentile scenarios forecast almost no growth in irrigation load over the 2005–2025 time period. In the 70th percentile scenario, irrigation load is projected to be 203 average megawatts in 2005 and 203 average megawatts in 2025. The individual irrigation load forecasts are reported in Table 7 and shown in Figure 8. The figure illustrates the poorer economic conditions and the drop-off in land development experienced by the agricultural economy in the mid-1980s.

Table 7. Irrigation Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
90th Percentile	224	224	222	225	0.0%
70th Percentile	203	202	201	203	0.0%
Expected Case.....	186	186	184	187	0.0%

One must be careful in interpreting the meaning of the annual average load figures being reported in Table 7 and graphed in Figure 8. The average loads being reported are calculated using the 8,760 hours of a typical year. In the highly seasonal irrigation sector, over 96 percent of the annual energy is billed during the six months from May through October, and

Figure 8. Forecasted Irrigation Load
(average megawatts)



nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads at generation level can reach the 750–800 megawatt range. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy generated during the hour of the annual system peak and 29 percent of the energy generated during the month for general business sales. Note that it is the monthly forecast figures that are being evaluated for resource planning purposes, not the annual average loads.

In early 2001 wholesale electricity prices reached unprecedented levels and Idaho Power, in an attempt to minimize reliance on the market, developed a voluntary load reduction program that paid irrigators not to use electricity in 2001. The voluntary load-reduction program was effective and resulted in a 30 percent reduction in 2001 irrigation sales or approximately 499,319 MWh. The 2001 irrigation sales and corresponding loads have been adjusted upward by 499,319 MWh to reflect a more normal 2001 irrigation season. In the future, Idaho Power does not anticipate that it will be necessary to implement similar load-reduction programs to irrigators.

The 2006 irrigation sales forecast considers several factors affecting electricity sales to the irrigation class including temperature, precipitation, spring rainfall, and the price of electricity. Considerations were made for the unusually low electricity consumption in the 2001 crop year due to the voluntary load-reduction program.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 1,990,000 MWh in 2000. During the period 1970–1996, the Company experienced an increase in electricity-using irrigated acres of 1,179,000 acres. This growth in total electricity-using irrigated acres represented approximately a 2.9 percent average annual compound rate of growth. The Company projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented 15 percent of weather-normalized company system sales in 1970. Irrigation sales reached a maximum proportion of nearly 20 percent of company system sales in 1975–1977. In 2005 the irrigation proportion of system sales was 12 percent. By 2025 irrigation customers are projected to consume less than nine percent of company system sales. The customer load proportions are shown in Figure 19.

In 1970 Idaho Power had about 7,300 active irrigation accounts. By 2005 the number of active irrigation accounts had increased to nearly 17,000 and there is projected to be nearly 22,600 irrigation accounts at the end of the planning period in 2025.

Since 1988, the Company has experienced growth in the number of irrigation customers, but no growth in electricity sales (weather-adjusted). The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low. Also, the kWh use-per-customer for these customers is substantially less than the average existing Idaho Power irrigation customer. This is due to the fact that water is drawn from canals and not from deep groundwater wells.

Bell Rapids has historically been the Company's largest irrigation customer. The combined Bell Rapids accounts included more than 40 individual irrigation service points that accounted for approximately 3–4 percent of the Company's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids for $24,375,000, which resulted in the loss of Bell Rapids as an irrigation customer. As a result, the irrigation sales forecast was reassessed and revised downward throughout the forecast period. In previous years, Bell Rapids had consumed on average approximately 55,000 MWh each year. In the future, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

INDUSTRIAL

The industrial category is made up of Idaho Power Company's Large Power Service (Schedule 19) customers with metered demands exceeding 1,000 kilowatts. There were about 50 industrial customers of Idaho Power in 1970 that represented eight percent of the Company's system sales. By December 2005 the number of industrial customers had risen to 129, representing about 18 percent of system sales.

In the expected case forecast, industrial load grows from 269 average megawatts in 2005 to 423 average megawatts in 2025, an average annual growth rate of 2.3 percent (see Table 8). As a general rule, industrial loads are not weather-sensitive, and the forecasts in the 70th and 90th percentile scenarios are identical to the expected case industrial load scenario. The industrial load forecast is pictured in Figure 9.

Figure 9. Forecasted Industrial Load
(average megawatts)

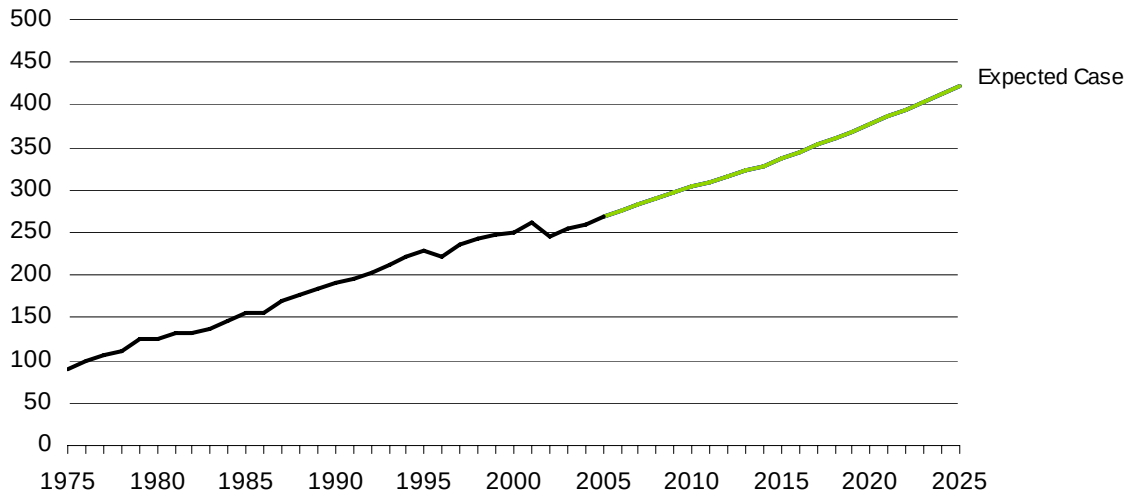


Table 8. Industrial Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
Expected Case.....	269	304	337	423	2.3%

The industrial energy forecast is based upon service area employment projections taken from the 2006 Economic Forecast. The Company's Schedule 19 customers were categorized and their historical electricity sales were summarized by economic activity. The appropriate employment series were then matched to each economic sector or industry group. Regression models were developed for 16 industry groups to determine the relationship between historical electricity sales and historical employment. The estimated coefficients from the industry group regression models were then applied to the appropriate employment drivers from the 2006 Economic Forecast, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2005 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (48 percent), followed by Stone, Clay, Glass, and Concrete Products (7 percent), Industrial and Commercial Machinery (6 percent), Health Services (5 percent), and Electronic and Other Electrical Equipment (5 percent). As the chart shows, several other industry groups make up the remaining share of the 2005 industrial electricity consumption.

ADDITIONAL FIRM LOAD

Special contracts exist for five large customers that are recognized as firm load customers. These customers are Micron Technology, Simplot Fertilizer, Idaho National Laboratory (INL), the City of Weiser, and Raft River Rural Electric Cooperative, Inc. (Raft River). Together, these customers make up the additional firm load category.

In the expected case forecast, additional firm load is expected to increase from 134 average megawatts in 2005 to 163 average megawatts in the year 2025, an average growth rate of 1 percent per year over the planning period (see Table 9). The additional firm load energy and demand forecasts in the 70th and 90th percentile scenarios are identical to the expected load growth scenario. The scenario of projected additional firm load is illustrated in Figure 11.

Figure 10. Industrial Electricity Consumption by Industry Group
(based on 2005 figures)

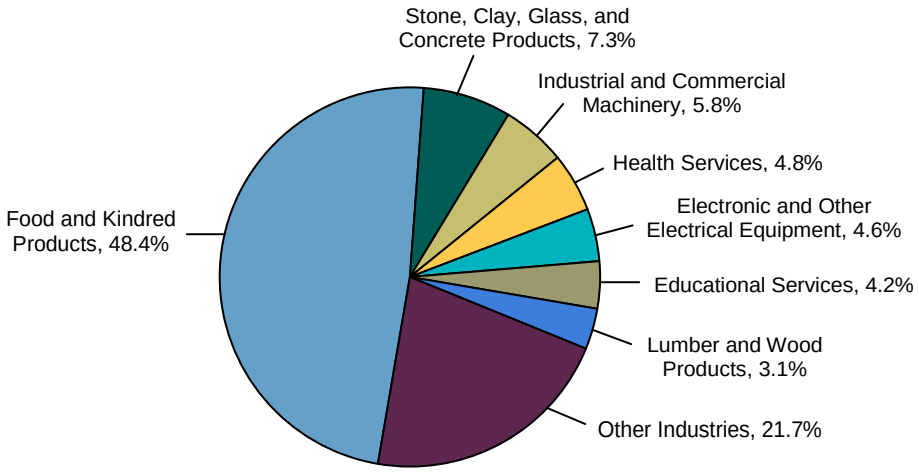


Figure 11. Forecasted Additional Firm Load
(average megawatts)

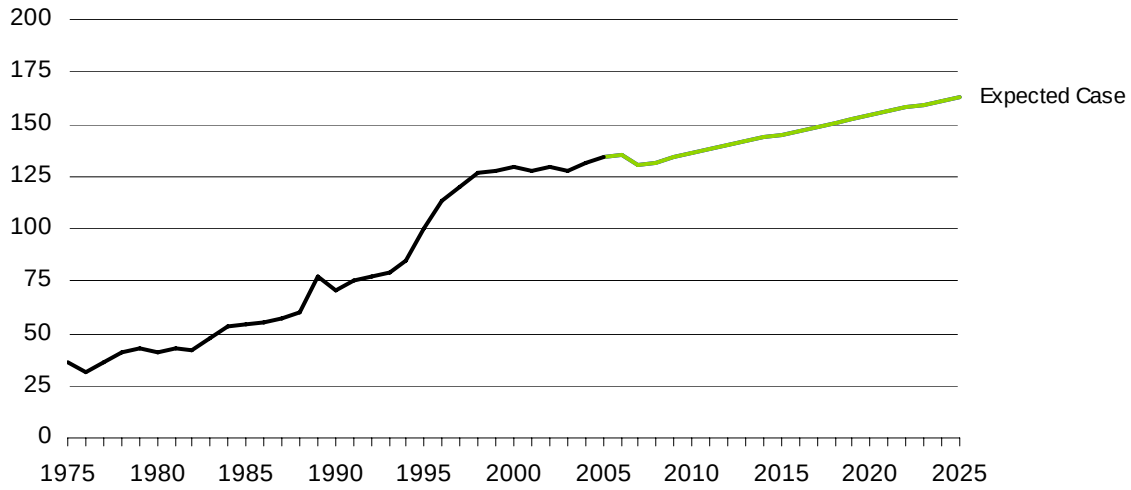


Table 9. Additional Firm Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
Expected Case.....	134	136	145	163	1.0%

Micron Technology

Micron Technology is currently the Company's largest individual customer. In this forecast, electricity sales to Micron Technology are expected to steadily rise throughout the forecast period. The primary driver of long-term electricity sales growth at Micron Technology is employment growth in the Electronic Equipment sector as provided by the 2006 Economic Forecast.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. In August of 2002, Simplot Fertilizer closed its ammonia production facility. The ammonia plant represented about 11 MW or about one-third of the entire Simplot load. The ammonia is now being purchased on contract from an outside supplier. Offsetting the decline is the equipment required to unload and store the ammonia, which accounts for an additional 3 or 4 MW. The future electricity usage at the plant is expected to continue to increase, although at a much slower rate of growth. Employment growth in the Chemical and Allied Products sector is the primary driver of long-term electricity sales growth at Simplot Fertilizer.

Idaho National Laboratory (INL)

The Department of Energy provided an energy consumption and peak demand forecast through 2015 for the INL. The forecast calls for loads to slowly increase through 2012 and then remain flat throughout the remaining forecast period. Looking back over a decade ago, the annual loads at the INL were quite volatile due to operational constraints affecting the availability of their nuclear reactor to generate electricity. However, as of October 1994, the INL nuclear reactor no longer generates electricity and, consequently, the amount of electricity provided by Idaho Power has increased considerably.

City of Weiser

The City of Weiser is surrounded by and dependent upon the economic health of the Idaho Power service area. Electricity sales to the City of Weiser are assumed to vary directly with household growth in Idaho's Washington

County, in which the City of Weiser resides. The long-term firm sales contract with the City of Weiser is expected to expire December 31, 2006, and will not be renewed.

Raft River Rural Electric Cooperative, Inc.

A term sales contract with Raft River was established as a full-requirements contract after being approved by the Federal Energy Regulatory Commission (FERC) and the Public Utility Commission of Nevada. Raft River is the electric distribution utility serving Idaho Power Company's former customers in the state of Nevada. Idaho Power Company sold the transmission facilities and rights-of-way that serve about 1,250 customers in northern Nevada and 90 customers in southern Owyhee County to Raft River. The closing date on the transaction was April 2, 2001. Raft River is also located entirely within Idaho Power Company's load control area.

The contract with Raft River expires September 30, 2006. However, Raft River may renew the agreement on a year-to-year basis for five additional one-year terms which would extend service until September 30, 2011. The load forecasts in the 2006 IRP assume that the Company will continue to serve the Raft River contract over the entire planning period (2006–2025).

COMPANY FIRM LOAD

Firm load is the sum of the individual loads of the residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), the City of Weiser, and Raft River. Firm load excludes not only Astaris, but also all contracts to provide firm energy to off-system customers. Without the dampening effects of Astaris and expiring off-system contracts on load growth, firm load more accurately portrays the underlying growth trend within the service area than total load, which includes both Astaris and off-system commitments. The expiration of off-system contracts also explains why the 2005 firm load figures shown in Table 10 are slightly lower than the 2005 total load figures shown in Table 14.

Table 10. Firm Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
90th Percentile	1,801	2,008	2,175	2,601	1.9%
70th Percentile	1,733	1,935	2,097	2,515	1.9%
Expected Case	1,693	1,892	2,051	2,464	1.9%

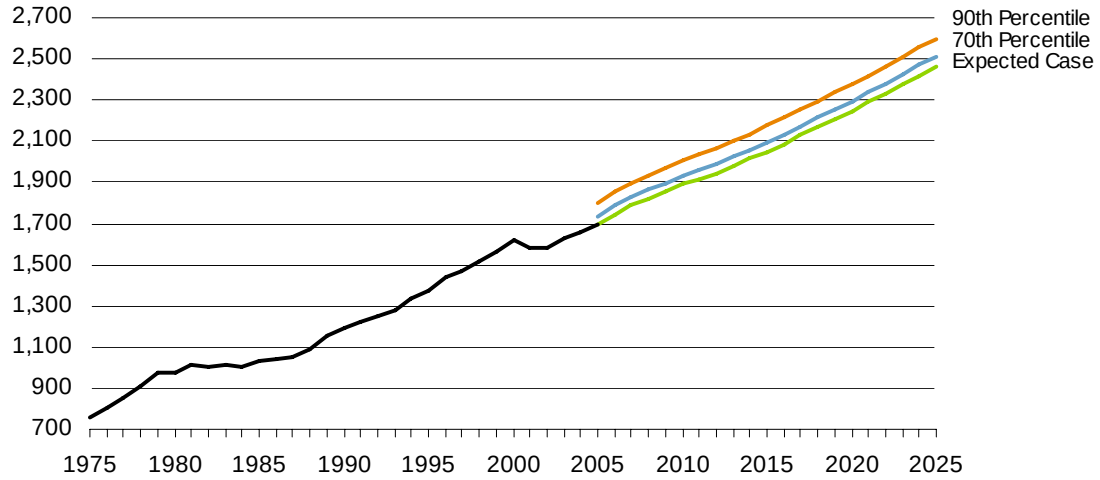
In the expected case forecast, total firm load is expected to increase from 1,693 average megawatts in 2005, reaching 2,464 average megawatts in the year 2025, an average growth rate of 1.9 percent per year over the planning period (see Table 10). In the 70th percentile forecast, total firm load is expected to increase from 1,733 average megawatts in 2005, reaching 2,515 average megawatts in the year 2025, an average growth rate of 1.9 percent per year over the planning period (see Table 10). The three scenarios of projected firm load are illustrated in Figure 12.

COMPANY FIRM PEAK

As defined here, firm peak load includes the sum of the individual coincident peak demands of the residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), the City of Weiser, and Raft River.

The all-time firm summer peak demand was 3,084 megawatts, recorded on Monday, July 24, 2006, at 6:00 p.m. The previous year's summer peak demand was 2,961 megawatts and occurred on Friday, July 22, 2005, at 4:00 p.m. The summer firm peak load growth has accelerated over the past ten years as air conditioning has become standard in nearly all

Figure 12. Forecasted Firm Load
(average megawatts)



new residential home construction and new commercial buildings. The 2001 summer peak was dampened by the nearly 30 percent cutback in irrigation load due to the 2001 voluntary load reduction program.

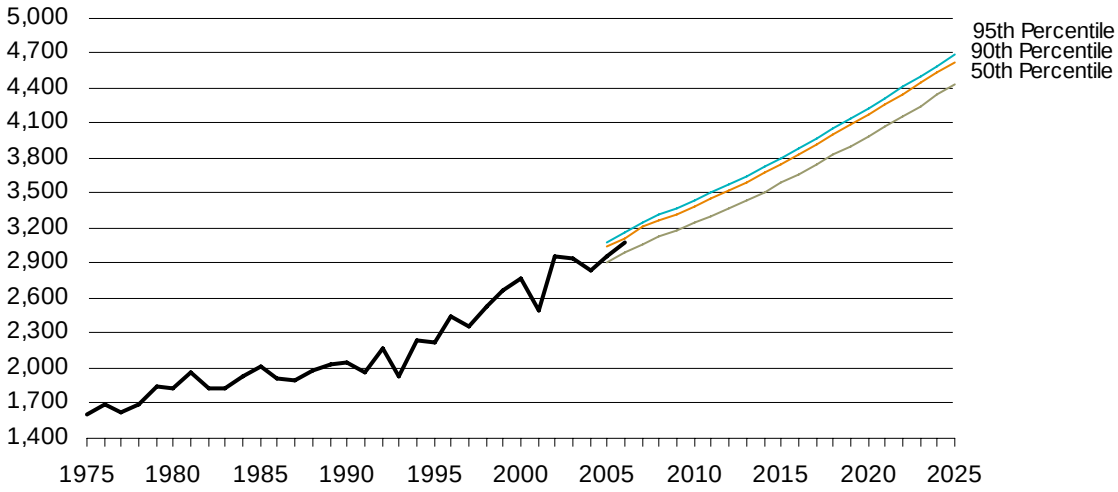
In the 90th percentile forecast, total firm summer peak load is expected to increase from 3,044 megawatts in 2005, reaching 4,627 megawatts in the year 2025, an average growth rate of 2.1 percent per year over the planning period (see Table 11).

In the 95th percentile forecast, total firm summer peak load is expected to increase from 3,084 megawatts in 2005, reaching 4,689 megawatts in the year 2025. The three scenarios of projected firm summer peak load are illustrated in Figure 13.

Table 11. Firm Summer Peak Load Growth
(megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
95th Percentile	3,084	3,442	3,805	4,689	2.1%
90th Percentile	3,044	3,396	3,754	4,627	2.1%
50th Percentile	2,913	3,248	3,589	4,428	2.1%

Figure 13. Forecasted Firm Summer Peak
(megawatts)



The maximum firm winter peak demand was 2,342 megawatts reached in December 1998. As shown in Figure 14, historical winter firm peak load is more variable than summer firm peak load. This is because the range in peak-day temperatures in winter months is far greater than the range in peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 14 illustrates the higher variability associated with winter peak-day temperatures.

In the 90th percentile forecast, total firm winter peak load is expected to increase from 2,576 megawatts in 2005, reaching 3,547 megawatts in the year 2025, an average growth rate of 1.6 percent per year over the planning period (see Table 12). In the 95th percentile forecast, total firm winter peak load is expected to increase from 2,679 megawatts in 2005, reaching 3,696 megawatts in the year 2025, an average growth rate of 1.6 percent per year over the planning period (see Table 12). The three scenarios of projected firm winter peak load are illustrated in Figure 14.

Table 12. Firm Winter Peak Load Growth
(megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
95th Percentile	2,679	2,948	3,121	3,696	1.6%
90th Percentile	2,576	2,833	2,996	3,547	1.6%
50th Percentile	2,287	2,511	2,648	3,134	1.6%

ASTARIS LOAD

The Astaris elemental phosphorous plant, located on the western edge of Pocatello, Idaho, ceased large-scale production in mid-December of 2001. Four months later, in April 2002, the special contract between Astaris and Idaho Power Company was terminated. Since then, Astaris (now FMC Corporation) has been billed for electric service as a Schedule 19 customer (see Industrial discussion). Therefore, Astaris load is zero (since May 1, 2002 as a special contract customer). Astaris had been the Company's largest individual customer and in some past years had averaged nearly 200 megawatts each month. The historical average annual load at Astaris is presented in Figure 15.

Figure 14. Forecasted Firm Winter Peak
(megawatts)

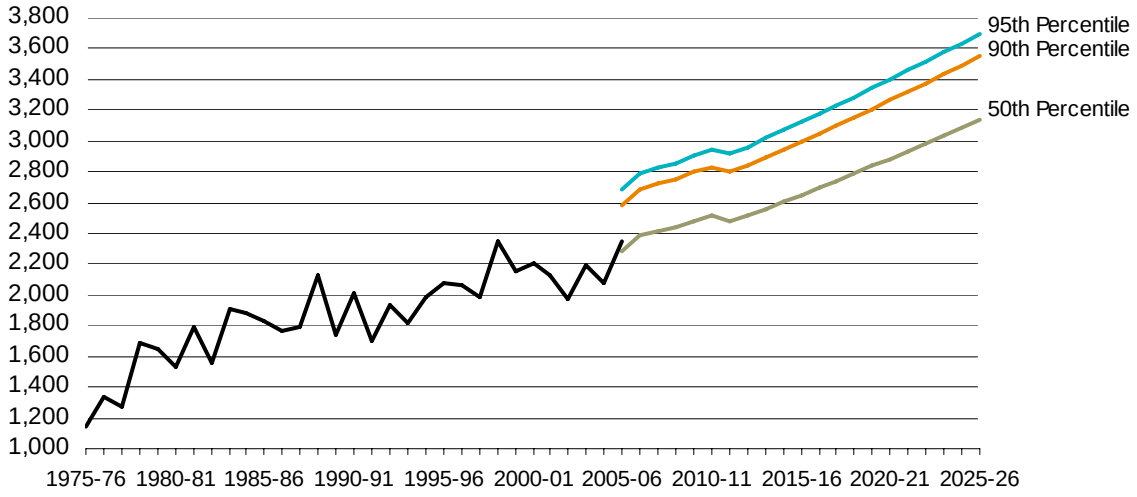
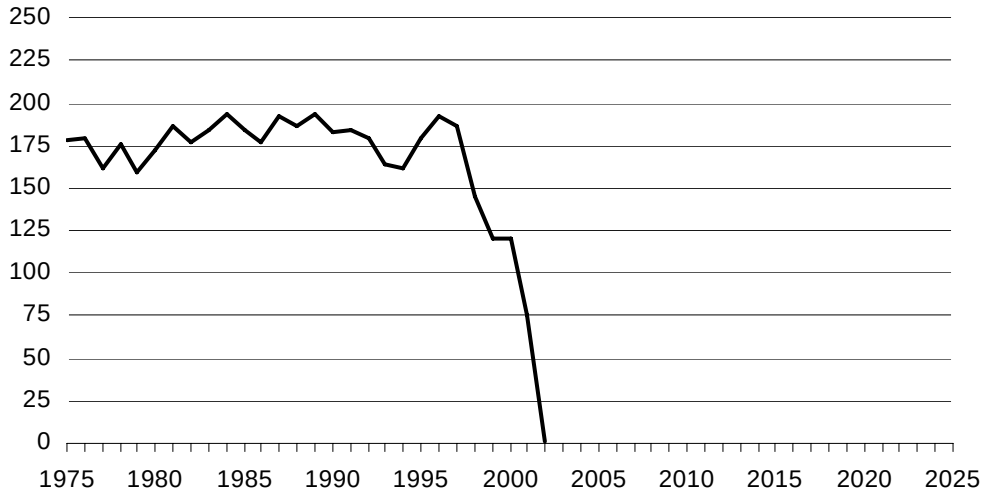


Figure 15. Historical Astaris (FMC) Load
(average megawatts)



COMPANY SYSTEM LOAD

System load historically has been made up of firm load plus Astaris load, but has excluded long-term off-system contracts. Since Astaris ceased production in April 2002, system load and firm load have been identical.

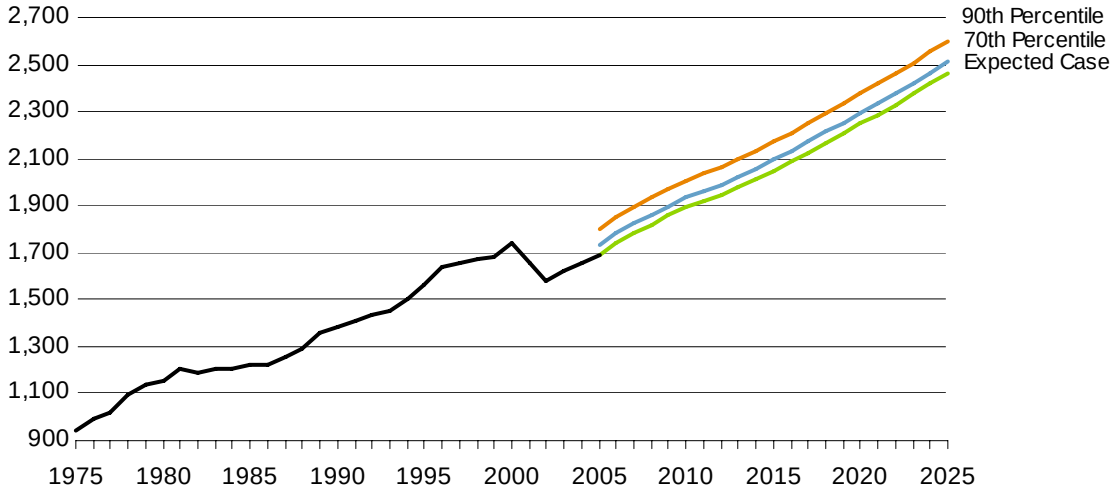
The expected case system load forecast is based upon an economic forecast for the service area and represents Idaho Power's most probable load growth during the planning period. The expected case forecast system load growth rate averages 1.9 percent per year over the 2005–2025 time period. Company system load projections are reported in Table 13 and shown in Figure 16.

Table 13. System Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
90th Percentile	1,801	2,008	2,175	2,601	1.9%
70th Percentile	1,733	1,935	2,097	2,515	1.9%
Expected Case	1,693	1,892	2,051	2,464	1.9%

In the expected case forecast, Company system load is expected to increase from 1,693 average megawatts in 2005, to 2,464 average megawatts

Figure 16. Forecasted System Load
(average megawatts)



in the year 2025. In the 70th percentile forecast, Company system load is expected to increase from 1,733 average megawatts in 2005, reaching 2,515 average megawatts in the year 2025—an average growth rate of 1.9 percent per year over the planning period (see Table 13).

CONTRACT OFF-SYSTEM LOAD

The contract off-system category represents long-term contracts to supply firm energy to off-system customers. Long-term contracts are contracts with a duration greater than one year and effective during the forecast period. At this time, there are no long-term contracts that remain. The last long-term contract—with Colton, California—expired in May 2005 and was not renewed. Long-term contracts with Washington City and Utah Associated Municipal Power Systems (UAMPS) expired in June 2002 and December 2003, respectively, and were not renewed.

As illustrated in Figure 17, the historical consumption for the contract off-system load category was considerable in the early 1990s; however, after 1995, off-system loads declined through 2005. As intended, the off-system contracts and their corresponding energy requirements expired as the Company's surplus energy diminished due to retail load growth.

TOTAL COMPANY LOAD

Accompanied by an outlook of moderate economic growth for the Idaho Power service area throughout the forecast period, the 2006 Sales and Load Forecast projects continued growth in the Company's total load.

Total load is made up of system load plus long-term firm off-system contracts. As previously mentioned, the remaining long-term off-system contract with Colton, California, expired in May 2005 and was not renewed.

Total company load projections are listed in Table 14 and illustrated in Figure 18. The expected case scenario average growth rate of 1.9 percent per year represents the most probable outlook expected by the Company. In the 70th percentile forecast, Company total load is expected to increase from 1,734 average megawatts in 2005 and reach 2,515 average megawatts in the year 2025.

Figure 17. Forecasted Contract Off-System Load by Customer
(average megawatts)

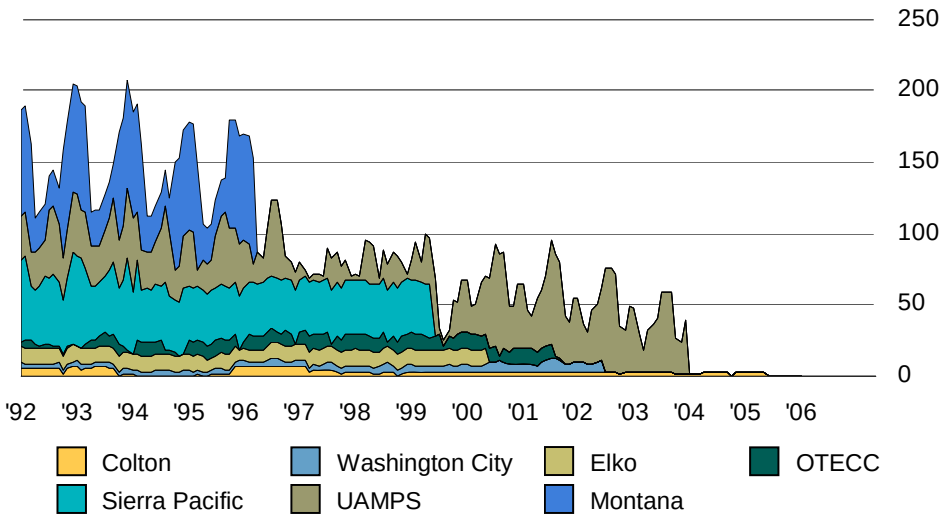


Figure 18. Forecasted Total Load
(average megawatts)

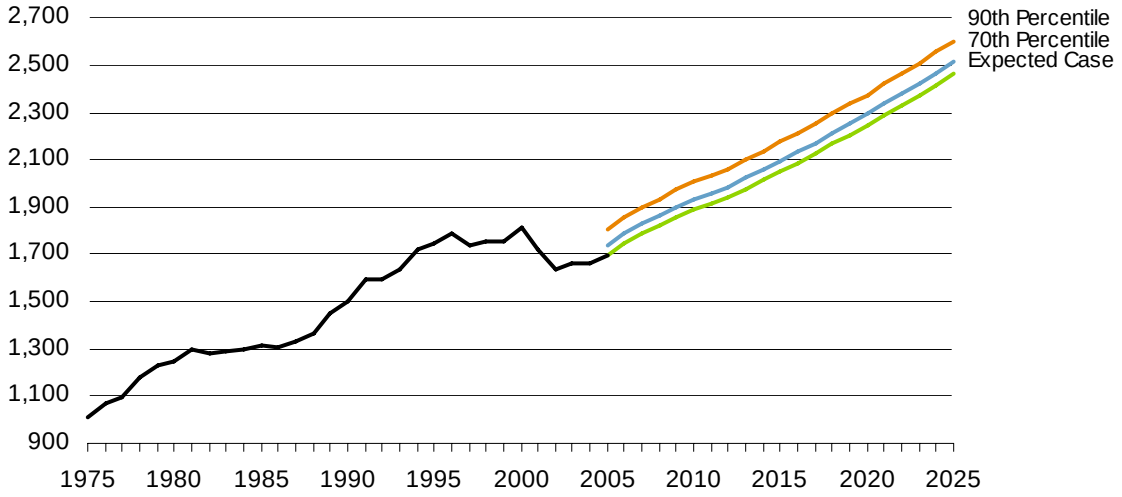


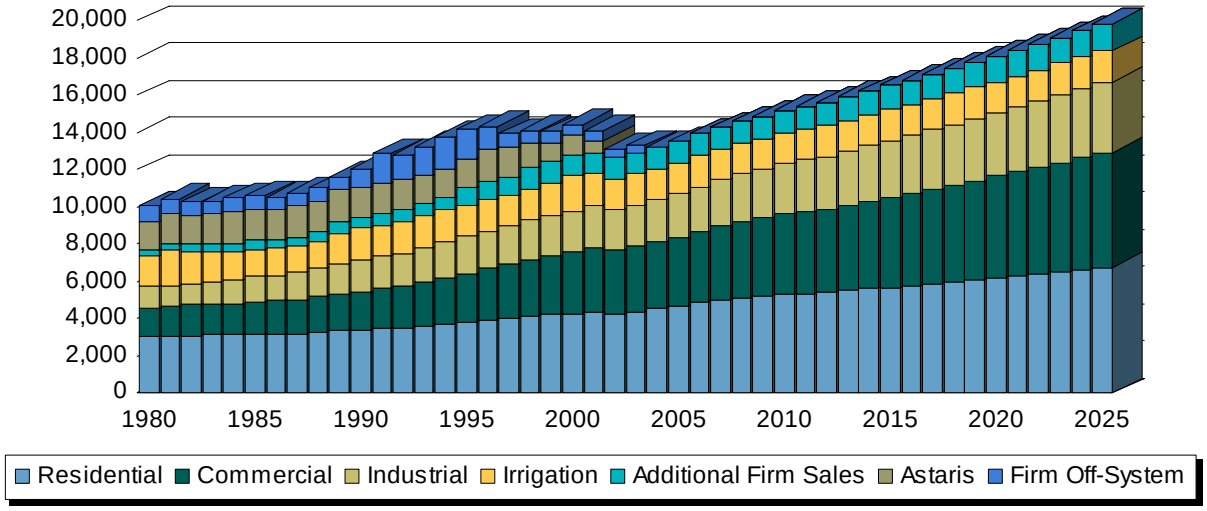
Table 14. Total Company Load Growth
(average megawatts)

	2005	2010	2015	2025	Growth Rate (per year) 2005–2025
90th Percentile	1,802	2,008	2,175	2,601	1.9%
70th Percentile	1,734	1,935	2,097	2,515	1.9%
Expected Case	1,694	1,892	2,051	2,464	1.9%

The composition of total company electricity sales by year is shown in Figure 19. Residential sales are forecast to be over 43 percent higher in 2025, gaining nearly 2.0 million MWh over 2005. Commercial sales are expected to be nearly 68 percent higher or nearly 2.5 million MWh above 2005 followed by industrial (57 percent higher or nearly 1.3 million additional MWh) and irrigation (only 0.2 percent higher in 2025). Electricity sales to Astaris, as a special contract customer, ended in April 2002.

The additional firm sales category (which represents sales to Micron Technology, Simplot Fertilizer, INL, City of Weiser, and Raft River) is forecast to grow by nearly 21 percent over the 2005–2025 time period.

Figure 19. Composition of Electricity Sales
(thousands of MWh)



DEMAND-SIDE MANAGEMENT (DSM)

The future load impacts of implemented and committed Idaho Power DSM programs are considered within the 2006 Sales and Load Forecast. The six programs that were identified for implementation in the 2004 IRP were in place and operating by the end of 2005. The four Energy Efficiency programs—ENERGY STAR® Homes Northwest, Commercial Building Efficiency, Industrial Efficiency, and Irrigation Efficiency Rewards—resulted in a savings of 13,946 MWh in 2005. The two Demand Response programs, A/C Cool Credit and Irrigation Peak Rewards, resulted in a combined reduction of peak demand of over 43 MW in the summer of 2005.

The forecasts of the energy and peak demand impacts associated with each of the four Energy Efficiency programs and the peak demand impacts of the two Demand Response programs have been subtracted from the load forecast. The final load forecast (adjusted downward for DSM) will be used in all studies and analysis related to the 2006 IRP. The energy and peak demand estimates associated with each of the six implemented and committed DSM programs are included in Appendix A2.

DSM energy and peak demand estimates are typically measured at the point of delivery (customers' meters). In order to make the numbers comparable to supply-side resources, which are typically measured at the point of generation, the DSM numbers are increased by the amount of energy lost in transmission from the generation source to the customers' point of use.

Brief descriptions of the four Energy Efficiency programs and the two Demand Response programs follow.

Energy Efficiency Programs

DSM Energy Efficiency initiatives were developed for all of Idaho Power customer sectors including residential, commercial, industrial, and irrigation. A common theme of the Energy Efficiency programs is the focus on identifying significant segments within the customer base where prevalent energy practices can be modified to deliver desired energy savings.

ENERGY STAR® Homes Northwest

The ENERGY STAR® Homes Northwest Program is a regionally coordinated initiative supported in partnership between Idaho Power, the Northwest Energy Efficiency Alliance (NEEA), and the Idaho Energy Division in support of improved construction practices of single-family homes. The energy goal of the program is to provide homes that are 30 percent more energy-efficient than those built to standard Idaho residential building codes. Idaho Power's energy focus for the program is to reduce future peak summer demand by increasing the efficiency of residential building envelope construction practices and increasing the efficiency of summer air conditioning use.

Commercial Building Efficiency

The Commercial Building Efficiency program targets those commercial customers involved in significant construction projects to which energy-efficient technologies and methods can be applied.

Industrial Efficiency

The Industrial Efficiency program is offered to large commercial and industrial customers of Idaho Power in both Idaho and Oregon. The program targets the acquisition of peak demand and energy savings from efficiency projects at customer sites through evaluation of existing facilities.

Irrigation Efficiency Rewards

The Irrigation Efficiency Rewards program is designed to improve the energy efficiency of water-pumping systems in Idaho Power's service area. The program provides a wide range of financial incentives and educational programs designed to serve the diversity of irrigators' needs.

Demand Response Programs

The goal of DSM Demand Response programs at Idaho Power is to reduce the summer peak demand periods and at the same time reduce the need for high-cost supply-side alternatives such as combustion turbines or open market electricity purchases.

The Demand Response programs at Idaho Power consist of A/C Cool Credit and Irrigation Peak Rewards.

A/C Cool Credit

A/C Cool Credit is a voluntary program for residential customers. The program enables Idaho Power to directly address summer peaking requirements by reducing air conditioning load at critical high-demand periods in the summertime. Control of the air conditioning units is achieved through the installation of individual radio-controlled switches on customer equipment and is cycled on and off using a predetermined schedule.

Irrigation Peak Rewards

The Irrigation Peak Rewards program was developed as a pilot program in the summer of 2004 and expanded to a system-wide program in late 2005. The program was developed after selection through the 2004 IRP process.

The voluntary program targets irrigation customers with pumps of 100 horsepower or greater with an objective of reducing peak electrical demand during summer weekday afternoons by providing control over the timing and operation of irrigation pumps. The program utilizes electronic time-activated switches to turn off pumps of participating irrigation customers during predetermined intervals.

An expanded and more thorough description of each of the DSM programs listed above is included as *Appendix B–Demand-Side Management 2005 Annual Report* of the 2006 Integrated Resource Plan.

Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1970–2005
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	132,135		9,983	1,319		152
1971	138,071	4.5%	10,538	1,455	10.3%	167
1972	145,208	5.2%	10,956	1,591	9.3%	184
1973	152,957	5.3%	11,524	1,763	10.8%	202
1974	160,151	4.7%	12,064	1,932	9.6%	223
1975	167,622	4.7%	12,943	2,170	12.3%	250
1976	175,720	4.8%	13,464	2,366	9.1%	271
1977	184,561	5.0%	13,681	2,525	6.7%	290
1978	194,650	5.5%	14,288	2,781	10.2%	321
1979	202,982	4.3%	14,764	2,997	7.8%	342
1980	209,629	3.3%	14,637	3,068	2.4%	350
1981	213,579	1.9%	14,384	3,072	0.1%	350
1982	216,696	1.5%	14,424	3,126	1.7%	357
1983	219,849	1.5%	14,366	3,158	1.0%	363
1984	222,695	1.3%	14,153	3,152	-0.2%	357
1985	225,185	1.1%	14,065	3,167	0.5%	362
1986	227,081	0.8%	14,162	3,216	1.5%	367
1987	228,868	0.8%	14,077	3,222	0.2%	366
1988	230,771	0.8%	14,328	3,306	2.6%	377
1989	233,370	1.1%	14,357	3,351	1.3%	384
1990	238,117	2.0%	14,307	3,407	1.7%	392
1991	243,207	2.1%	14,470	3,519	3.3%	401
1992	249,767	2.7%	14,133	3,530	0.3%	407
1993	258,271	3.4%	14,204	3,669	3.9%	414
1994	267,854	3.7%	13,985	3,746	2.1%	433
1995	277,131	3.5%	14,004	3,881	3.6%	438
1996	286,227	3.3%	13,758	3,938	1.5%	456
1997	294,674	3.0%	13,679	4,031	2.4%	463
1998	303,300	2.9%	13,685	4,151	3.0%	474
1999	312,901	3.2%	13,585	4,251	2.4%	487
2000	322,402	3.0%	13,370	4,310	1.4%	499
2001	331,009	2.7%	13,124	4,344	0.8%	475
2002	339,764	2.6%	12,610	4,284	-1.4%	488
2003	349,219	2.8%	12,631	4,411	3.0%	506
2004	360,462	3.2%	12,672	4,568	3.6%	523
2005	373,602	3.6%	12,643	4,724	3.4%	539

Residential Load

Projected Residential Sales and Load, 2006–2026

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	385,386	3.2%	12,623	4,865	3.0%	556
2007	396,087	2.8%	12,704	5,032	3.4%	575
2008	406,510	2.6%	12,632	5,135	2.1%	587
2009	416,185	2.4%	12,555	5,225	1.7%	596
2010	425,030	2.1%	12,526	5,324	1.9%	607
2011	433,670	2.0%	12,413	5,383	1.1%	614
2012	442,363	2.0%	12,250	5,419	0.7%	618
2013	451,236	2.0%	12,235	5,521	1.9%	629
2014	459,848	1.9%	12,219	5,619	1.8%	640
2015	468,344	1.8%	12,201	5,714	1.7%	651
2016	476,957	1.8%	12,183	5,811	1.7%	663
2017	485,832	1.9%	12,165	5,910	1.7%	674
2018	494,980	1.9%	12,147	6,013	1.7%	685
2019	504,264	1.9%	12,128	6,116	1.7%	697
2020	513,764	1.9%	12,109	6,221	1.7%	709
2021	523,563	1.9%	12,090	6,330	1.7%	722
2022	533,702	1.9%	12,071	6,442	1.8%	734
2023	544,002	1.9%	12,051	6,556	1.8%	747
2024	554,428	1.9%	12,031	6,671	1.7%	761
2025	565,000	1.9%	12,013	6,787	1.7%	774
2026	575,794	1.9%	11,994	6,906	1.8%	787

Commercial Load

Historical Commercial Sales and Load, 1970–2005

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	21,375		42,769	914		105
1971	22,077	3.3%	45,387	1,002	9.6%	115
1972	22,585	2.3%	46,140	1,042	4.0%	120
1973	23,286	3.1%	48,141	1,121	7.6%	128
1974	24,096	3.5%	49,025	1,181	5.4%	136
1975	25,045	3.9%	51,215	1,283	8.6%	147
1976	26,034	3.9%	52,509	1,367	6.6%	157
1977	27,112	4.1%	52,413	1,421	4.0%	162
1978	27,831	2.7%	52,468	1,460	2.8%	169
1979	28,087	0.9%	56,392	1,584	8.5%	180
1980	28,797	2.5%	54,137	1,559	-1.6%	178
1981	29,567	2.7%	54,279	1,605	2.9%	184
1982	30,167	2.0%	54,125	1,633	1.7%	186
1983	30,776	2.0%	52,585	1,618	-0.9%	186
1984	31,554	2.5%	53,232	1,680	3.8%	191
1985	32,417	2.7%	53,864	1,746	4.0%	200
1986	33,208	2.4%	53,399	1,773	1.6%	203
1987	33,975	2.3%	52,932	1,798	1.4%	205
1988	34,723	2.2%	54,206	1,882	4.7%	215
1989	35,638	2.6%	55,277	1,970	4.7%	226
1990	36,785	3.2%	55,960	2,058	4.5%	236
1991	37,922	3.1%	55,899	2,120	3.0%	243
1992	39,022	2.9%	56,220	2,194	3.5%	252
1993	40,047	2.6%	57,600	2,307	5.1%	261
1994	41,629	4.0%	58,196	2,423	5.0%	280
1995	43,165	3.7%	58,545	2,527	4.3%	287
1996	44,995	4.2%	61,981	2,789	10.4%	322
1997	46,819	4.1%	61,981	2,902	4.1%	333
1998	48,404	3.4%	62,800	3,040	4.8%	348
1999	49,430	2.1%	64,014	3,164	4.1%	362
2000	50,117	1.4%	66,115	3,313	4.7%	384
2001	51,501	2.8%	67,333	3,468	4.7%	383
2002	52,915	2.7%	64,659	3,421	-1.3%	390
2003	54,194	2.4%	64,333	3,486	1.9%	399
2004	55,577	2.6%	63,975	3,556	2.0%	407
2005	57,145	2.8%	63,506	3,629	2.1%	414

Commercial Load

Projected Commercial Sales and Load, 2006–2026

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	59,072	3.4%	64,361	3,802	4.8%	435
2007	60,895	3.1%	64,700	3,940	3.6%	450
2008	62,680	2.9%	64,834	4,064	3.1%	464
2009	64,350	2.7%	64,976	4,181	2.9%	478
2010	65,886	2.4%	65,237	4,298	2.8%	491
2011	67,388	2.3%	65,137	4,389	2.1%	501
2012	68,899	2.2%	64,967	4,476	2.0%	511
2013	70,438	2.2%	65,230	4,595	2.6%	524
2014	71,936	2.1%	65,491	4,711	2.5%	537
2015	73,414	2.1%	65,748	4,827	2.5%	551
2016	74,912	2.0%	66,000	4,944	2.4%	564
2017	76,452	2.1%	66,245	5,064	2.4%	578
2018	78,036	2.1%	66,482	5,188	2.4%	592
2019	79,643	2.1%	66,713	5,313	2.4%	606
2020	81,284	2.1%	66,938	5,441	2.4%	621
2021	82,975	2.1%	67,154	5,572	2.4%	636
2022	84,718	2.1%	67,363	5,707	2.4%	651
2023	86,487	2.1%	67,564	5,843	2.4%	667
2024	88,273	2.1%	67,760	5,981	2.4%	682
2025	90,079	2.0%	67,949	6,121	2.3%	698
2026	91,913	2.0%	68,131	6,262	2.3%	715

Irrigation Load

Historical Irrigation Sales and Load, 1970–2005

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	7,319		112,959	827		94
1971	7,518	2.7%	132,062	993	20.1%	113
1972	7,815	4.0%	127,402	996	0.3%	113
1973	8,341	6.7%	133,842	1,116	12.1%	127
1974	8,971	7.6%	142,631	1,280	14.6%	146
1975	9,480	5.7%	153,399	1,454	13.7%	166
1976	9,936	4.8%	153,729	1,527	5.0%	174
1977	10,238	3.0%	152,580	1,562	2.3%	178
1978	10,476	2.3%	153,345	1,606	2.8%	184
1979	10,711	2.2%	157,304	1,685	4.9%	191
1980	10,854	1.3%	154,154	1,673	-0.7%	191
1981	11,248	3.6%	164,287	1,848	10.4%	211
1982	11,312	0.6%	150,192	1,699	-8.1%	194
1983	11,133	-1.6%	144,849	1,613	-5.1%	184
1984	11,375	2.2%	129,161	1,469	-8.9%	167
1985	11,576	1.8%	127,094	1,471	0.1%	168
1986	11,308	-2.3%	128,586	1,454	-1.2%	166
1987	11,254	-0.5%	124,634	1,403	-3.5%	160
1988	11,378	1.1%	127,821	1,454	3.7%	166
1989	11,957	5.1%	135,779	1,624	11.6%	185
1990	12,340	3.2%	140,129	1,729	6.5%	197
1991	12,484	1.2%	135,437	1,691	-2.2%	193
1992	12,809	2.6%	133,927	1,715	1.5%	195
1993	13,078	2.1%	132,056	1,727	0.7%	197
1994	13,559	3.7%	125,938	1,708	-1.1%	195
1995	13,679	0.9%	124,644	1,705	-0.2%	195
1996	14,074	2.9%	122,689	1,727	1.3%	197
1997	14,383	2.2%	112,330	1,616	-6.4%	184
1998	14,695	2.2%	113,198	1,663	3.0%	190
1999	14,912	1.5%	116,149	1,732	4.1%	198
2000	15,253	2.3%	121,792	1,858	7.3%	211
2001	15,522	1.8%	109,994	1,707	-8.1%	195
2002	15,840	2.0%	104,078	1,649	-3.4%	188
2003	16,020	1.1%	105,345	1,688	2.4%	193
2004	16,297	1.7%	103,074	1,680	-0.5%	191
2005	16,936	3.9%	96,390	1,632	-2.8%	186

Irrigation Load

Projected Irrigation Sales and Load, 2006–2026

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	17,305	2.2%	95,348	1,650	1.1%	188
2007	17,582	1.6%	93,966	1,652	0.1%	187
2008	17,860	1.6%	92,542	1,653	0.0%	186
2009	18,137	1.6%	91,274	1,655	0.2%	186
2010	18,415	1.5%	90,018	1,658	0.1%	186
2011	18,690	1.5%	88,503	1,654	-0.2%	185
2012	18,966	1.5%	87,349	1,657	0.2%	184
2013	19,243	1.5%	86,225	1,659	0.2%	184
2014	19,520	1.4%	85,131	1,662	0.2%	184
2015	19,799	1.4%	84,060	1,664	0.2%	184
2016	20,073	1.4%	83,036	1,667	0.1%	184
2017	20,352	1.4%	82,021	1,669	0.2%	185
2018	20,630	1.4%	81,036	1,672	0.1%	185
2019	20,906	1.3%	80,082	1,674	0.1%	185
2020	21,183	1.3%	79,149	1,677	0.1%	185
2021	21,459	1.3%	78,242	1,679	0.1%	186
2022	21,737	1.3%	77,350	1,681	0.1%	186
2023	22,012	1.3%	76,488	1,684	0.1%	186
2024	22,289	1.3%	75,641	1,686	0.1%	186
2025	22,565	1.2%	74,815	1,688	0.1%	187
2026	22,842	1.2%	74,006	1,690	0.1%	187

Industrial Load

Historical Industrial Sales and Load, 1970–2005

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	49		9,173,784	445		51
1971	50	3.3%	10,474,941	525	17.9%	60
1972	56	12.1%	10,944,714	615	17.2%	71
1973	63	12.3%	10,889,056	687	11.7%	79
1974	65	2.2%	11,464,249	739	7.6%	84
1975	71	10.5%	11,014,121	785	6.1%	90
1976	73	3.0%	11,681,540	858	9.3%	99
1977	85	15.1%	10,988,826	929	8.3%	106
1978	99	17.6%	9,786,753	972	4.7%	111
1979	109	9.6%	9,989,158	1,087	11.8%	126
1980	112	2.7%	9,894,706	1,106	1.7%	125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	-0.3%	9,797,522	1,194	2.7%	137
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	-0.1%	155
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	-1.0%	11,660,183	1,546	4.9%	176
1989	132	-0.6%	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	190
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	202
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	-15.9%	16,793,437	2,021	3.7%	230
1996	103	-14.4%	18,774,093	1,934	-4.3%	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	-2.3%	19,985,029	2,160	0.7%	247
2000	107	-0.8%	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	261
2002	111	-0.1%	19,441,876	2,156	-5.8%	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	269

Industrial Load

Projected Industrial Sales and Load, 2006–2026

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	125	-0.9%	19,507,611	2,438	3.7%	277
2007	126	0.8%	19,927,990	2,511	3.0%	284
2008	129	2.4%	19,934,190	2,572	2.4%	290
2009	130	0.8%	20,299,574	2,639	2.6%	297
2010	132	1.5%	20,508,725	2,707	2.6%	304
2011	132	0.0%	20,968,441	2,768	2.2%	310
2012	133	0.8%	21,304,026	2,833	2.4%	316
2013	136	2.3%	21,320,410	2,900	2.3%	323
2014	137	0.7%	21,655,094	2,967	2.3%	329
2015	138	0.7%	21,987,651	3,034	2.3%	337
2016	140	1.4%	22,157,009	3,102	2.2%	345
2017	141	0.7%	22,490,464	3,171	2.2%	353
2018	142	0.7%	22,830,086	3,242	2.2%	361
2019	143	0.7%	23,175,985	3,314	2.2%	369
2020	145	1.4%	23,366,013	3,388	2.2%	378
2021	145	0.0%	23,887,075	3,464	2.2%	386
2022	148	2.1%	23,924,761	3,541	2.2%	395
2023	149	0.7%	24,294,134	3,620	2.2%	404
2024	151	1.3%	24,506,941	3,701	2.2%	413
2025	151	0.0%	25,053,446	3,783	2.2%	423
2026	153	1.3%	25,277,338	3,867	2.2%	432

Additional Firm Sales and Load*

Historical Additional Firm Sales and Load, 1970–2005

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	318		36
1971	294	-7.6%	34
1972	284	-3.5%	32
1973	290	2.2%	33
1974	282	-2.8%	32
1975	314	11.2%	36
1976	277	-11.8%	31
1977	311	12.4%	36
1978	357	14.7%	41
1979	373	4.6%	43
1980	360	-3.6%	41
1981	376	4.5%	43
1982	368	-2.2%	42
1983	425	15.5%	48
1984	466	9.9%	53
1985	473	1.3%	54
1986	482	2.0%	55
1987	503	4.3%	57
1988	531	5.6%	60
1989	671	26.6%	77
1990	625	-6.8%	71
1991	661	5.7%	75
1992	681	3.0%	77
1993	689	1.3%	79
1994	741	7.5%	85
1995	877	18.4%	100
1996	988	12.6%	113
1997	1,048	6.0%	120
1998	1,112	6.2%	127
1999	1,121	0.8%	128
2000	1,143	1.9%	130
2001	1,118	-2.1%	128
2002	1,139	1.9%	130
2003	1,120	-1.7%	128
2004	1,157	3.3%	132
2005	1,175	1.6%	134

* Includes Micron Technology, Simplot Fertilizer, INL, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

Additional Firm Sales and Load*

Projected Additional Firm Sales and Load, 2006–2026

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	1,183	0.6%	135
2007	1,143	-3.3%	131
2008	1,163	1.7%	132
2009	1,177	1.3%	134
2010	1,194	1.4%	136
2011	1,210	1.3%	138
2012	1,228	1.5%	140
2013	1,241	1.1%	142
2014	1,257	1.4%	144
2015	1,274	1.3%	145
2016	1,294	1.5%	147
2017	1,307	1.0%	149
2018	1,323	1.2%	151
2019	1,339	1.2%	153
2020	1,356	1.3%	154
2021	1,369	0.9%	156
2022	1,383	1.0%	158
2023	1,397	1.0%	159
2024	1,413	1.2%	161
2025	1,425	0.8%	163
2026	1,436	0.8%	164

* Includes Micron Technology, Simplot Fertilizer, INL, City of Weiser, and Raft River Rural Electric Cooperative, Inc.

Company Firm Load

Historical Company Firm Load, 1970–2005

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	3,823		483
1971	4,269	11.7%	538
1972	4,527	6.1%	572
1973	4,977	9.9%	628
1974	5,415	8.8%	685
1975	6,005	10.9%	759
1976	6,395	6.5%	807
1977	6,748	5.5%	850
1978	7,177	6.4%	910
1979	7,726	7.7%	971
1980	7,766	0.5%	974
1981	8,049	3.7%	1,012
1982	7,987	-0.8%	1,004
1983	8,007	0.3%	1,011
1984	8,049	0.5%	1,006
1985	8,215	2.1%	1,033
1986	8,282	0.8%	1,040
1987	8,399	1.4%	1,052
1988	8,719	3.8%	1,092
1989	9,209	5.6%	1,159
1990	9,482	3.0%	1,195
1991	9,709	2.4%	1,217
1992	9,890	1.9%	1,246
1993	10,246	3.6%	1,278
1994	10,565	3.1%	1,335
1995	11,011	4.2%	1,373
1996	11,375	3.3%	1,436
1997	11,638	2.3%	1,464
1998	12,111	4.1%	1,517
1999	12,428	2.6%	1,560
2000	12,816	3.1%	1,618
2001	12,926	0.9%	1,580
2002	12,650	-2.1%	1,583
2003	12,939	2.3%	1,625
2004	13,228	2.2%	1,660
2005	13,511	2.1%	1,693

Company Firm Load

Projected Company Firm Load, 2006–2026

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	13,938	3.2%	1,746
2007	14,278	2.4%	1,786
2008	14,586	2.2%	1,822
2009	14,878	2.0%	1,857
2010	15,181	2.0%	1,892
2011	15,405	1.5%	1,918
2012	15,613	1.4%	1,942
2013	15,915	1.9%	1,978
2014	16,216	1.9%	2,014
2015	16,514	1.8%	2,051
2016	16,817	1.8%	2,089
2017	17,122	1.8%	2,128
2018	17,437	1.8%	2,167
2019	17,757	1.8%	2,207
2020	18,083	1.8%	2,248
2021	18,413	1.8%	2,290
2022	18,754	1.9%	2,333
2023	19,100	1.8%	2,376
2024	19,451	1.8%	2,419
2025	19,804	1.8%	2,464
2026	20,162	1.8%	2,509

Astaris Load

Historical Astaris Sales and Load, 1970–2005

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	1,657		189
1971	1,508	-9.0%	172
1972	1,819	20.6%	207
1973	1,645	-9.6%	188
1974	1,643	-0.1%	188
1975	1,557	-5.3%	178
1976	1,575	1.2%	179
1977	1,418	-10.0%	162
1978	1,542	8.8%	176
1979	1,395	-9.6%	159
1980	1,513	8.5%	172
1981	1,634	8.0%	186
1982	1,554	-4.9%	177
1983	1,610	3.6%	184
1984	1,701	5.7%	194
1985	1,614	-5.1%	184
1986	1,554	-3.7%	177
1987	1,692	8.9%	193
1988	1,635	-3.4%	186
1989	1,703	4.2%	194
1990	1,604	-5.8%	183
1991	1,609	0.3%	184
1992	1,570	-2.4%	179
1993	1,437	-8.4%	164
1994	1,420	-1.2%	162
1995	1,567	10.4%	179
1996	1,689	7.8%	192
1997	1,628	-3.6%	186
1998	1,273	-21.8%	145
1999	1,051	-17.4%	120
2000	1,054	0.3%	120
2001	658	-37.5%	75
2002	11	-98.3%	1
2003	0	-100.0%	0
2004	0	0.0%	0
2005	0	0.0%	0

Astaris Load

Projected Astaris Sales and Load, 2006–2026

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006–2026	0	0.0%	0

Company System Load

Historical Company System Sales and Load, 1970–2005

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	5,481		682
1971	5,777	5.4%	719
1972	6,347	9.9%	789
1973	6,622	4.3%	825
1974	7,058	6.6%	881
1975	7,562	7.1%	946
1976	7,970	5.4%	995
1977	8,165	2.5%	1,020
1978	8,719	6.8%	1,095
1979	9,121	4.6%	1,138
1980	9,279	1.7%	1,155
1981	9,683	4.4%	1,208
1982	9,541	-1.5%	1,191
1983	9,617	0.8%	1,204
1984	9,750	1.4%	1,209
1985	9,828	0.8%	1,226
1986	9,835	0.1%	1,226
1987	10,091	2.6%	1,254
1988	10,355	2.6%	1,288
1989	10,913	5.4%	1,363
1990	11,086	1.6%	1,388
1991	11,318	2.1%	1,410
1992	11,460	1.2%	1,434
1993	11,683	1.9%	1,450
1994	11,985	2.6%	1,506
1995	12,578	5.0%	1,560
1996	13,064	3.9%	1,638
1997	13,266	1.5%	1,659
1998	13,384	0.9%	1,670
1999	13,479	0.7%	1,686
2000	13,870	2.9%	1,744
2001	13,585	-2.1%	1,659
2002	12,661	-6.8%	1,584
2003	12,939	2.2%	1,625
2004	13,228	2.2%	1,660
2005	13,511	2.1%	1,693

Company System Load

Projected Company System Sales and Load, 2006–2026

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	13,938	3.2%	1,746
2007	14,278	2.4%	1,786
2008	14,586	2.2%	1,822
2009	14,878	2.0%	1,857
2010	15,181	2.0%	1,892
2011	15,405	1.5%	1,918
2012	15,613	1.4%	1,942
2013	15,915	1.9%	1,978
2014	16,216	1.9%	2,014
2015	16,514	1.8%	2,051
2016	16,817	1.8%	2,089
2017	17,122	1.8%	2,128
2018	17,437	1.8%	2,167
2019	17,757	1.8%	2,207
2020	18,083	1.8%	2,248
2021	18,413	1.8%	2,290
2022	18,754	1.9%	2,333
2023	19,100	1.8%	2,376
2024	19,451	1.8%	2,419
2025	19,804	1.8%	2,464
2026	20,162	1.8%	2,509

Contract Off-System Load

Historical Contract Off-System Sales and Load, 1970–2005

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	386		44
1971	439	13.6%	50
1972	448	2.0%	51
1973	489	9.3%	56
1974	501	2.3%	57
1975	568	13.5%	65
1976	613	7.9%	70
1977	659	7.5%	75
1978	684	3.7%	78
1979	759	11.1%	87
1980	762	0.3%	87
1981	752	-1.2%	86
1982	736	-2.2%	84
1983	710	-3.5%	81
1984	747	5.2%	85
1985	779	4.3%	89
1986	670	-13.9%	77
1987	644	-4.0%	73
1988	675	4.9%	77
1989	740	9.7%	84
1990	968	30.8%	111
1991	1,537	58.8%	175
1992	1,348	-12.3%	154
1993	1,557	15.5%	178
1994	1,811	16.3%	207
1995	1,583	-12.6%	181
1996	1,285	-18.8%	146
1997	674	-47.5%	77
1998	716	6.2%	82
1999	568	-20.6%	65
2000	587	3.3%	67
2001	538	-8.4%	61
2002	454	-15.7%	52
2003	346	-23.6%	40
2004	19	-94.4%	2
2005	10	-47.0%	1

Contract Off-System Load

Projected Contract Off-System Sales and Load, 2006–2026

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	0	-100.0%	0
2007–2026	0	0.0%	0

Total Company Load

Historical Total Company Sales and Load, 1970–2005

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
1970	5,867		727
1971	6,216	5.9%	771
1972	6,794	9.3%	842
1973	7,111	4.7%	883
1974	7,559	6.3%	941
1975	8,130	7.6%	1,013
1976	8,583	5.6%	1,067
1977	8,825	2.8%	1,098
1978	9,403	6.6%	1,176
1979	9,880	5.1%	1,228
1980	10,041	1.6%	1,244
1981	10,436	3.9%	1,297
1982	10,277	-1.5%	1,278
1983	10,327	0.5%	1,287
1984	10,497	1.6%	1,297
1985	10,607	1.0%	1,318
1986	10,506	-1.0%	1,305
1987	10,735	2.2%	1,330
1988	11,030	2.7%	1,367
1989	11,653	5.7%	1,450
1990	12,055	3.4%	1,502
1991	12,855	6.6%	1,592
1992	12,808	-0.4%	1,593
1993	13,240	3.4%	1,634
1994	13,796	4.2%	1,720
1995	14,161	2.6%	1,748
1996	14,349	1.3%	1,789
1997	13,940	-2.8%	1,739
1998	14,099	1.1%	1,754
1999	14,048	-0.4%	1,754
2000	14,457	2.9%	1,813
2001	14,123	-2.3%	1,723
2002	13,115	-7.1%	1,638
2003	13,286	1.3%	1,666
2004	13,248	-0.3%	1,662
2005	13,522	2.1%	1,694

Total Company Load

Projected Total Company Sales and Load, 2006–2026

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (megawatts)
2006	13,938	3.1%	1,746
2007	14,278	2.4%	1,786
2008	14,586	2.2%	1,822
2009	14,878	2.0%	1,857
2010	15,181	2.0%	1,892
2011	15,405	1.5%	1,918
2012	15,613	1.4%	1,942
2013	15,915	1.9%	1,978
2014	16,216	1.9%	2,014
2015	16,514	1.8%	2,051
2016	16,817	1.8%	2,089
2017	17,122	1.8%	2,128
2018	17,437	1.8%	2,167
2019	17,757	1.8%	2,207
2020	18,083	1.8%	2,248
2021	18,413	1.8%	2,290
2022	18,754	1.9%	2,333
2023	19,100	1.8%	2,376
2024	19,451	1.8%	2,419
2025	19,804	1.8%	2,464
2026	20,162	1.8%	2,509

Appendix A2. Demand-Side Management Program Impacts

Energy Efficiency Programs

ENERGY STAR® Homes Northwest

(megawatthours including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2006	122	113	115	104	190	305	491	495	328	119	114	128	2,625
2007	195	180	185	166	303	488	779	792	529	190	182	204	4,193
2008	268	257	253	228	418	674	1,072	1,102	722	262	250	279	5,784
2009	345	318	323	292	537	856	1,377	1,414	921	337	319	358	7,397
2010	430	396	403	366	667	1,066	1,718	1,751	1,144	421	397	447	9,205
2011	515	474	482	441	799	1,281	2,069	2,080	1,371	502	476	538	11,028
2012	598	571	567	507	930	1,496	2,389	2,428	1,621	583	557	625	12,872
2013	684	632	649	581	1,065	1,725	2,727	2,795	1,854	670	640	713	14,734
2014	772	712	728	655	1,202	1,938	3,083	3,170	2,076	754	719	803	16,612
2015	775	713	726	655	1,207	1,923	3,093	3,174	2,068	756	717	804	16,612
2016	776	738	726	663	1,202	1,926	3,111	3,129	2,062	755	717	808	16,612
2017	774	714	730	660	1,201	1,933	3,106	3,133	2,077	756	718	810	16,612
2018	772	713	733	656	1,202	1,934	3,088	3,138	2,095	754	720	807	16,612
2019	771	712	732	655	1,201	1,944	3,075	3,152	2,090	755	722	804	16,612
2020	773	739	725	655	1,205	1,920	3,088	3,170	2,065	755	716	803	16,612
2021	777	714	727	660	1,203	1,924	3,101	3,160	2,064	759	717	807	16,612
2022	775	714	727	664	1,204	1,929	3,116	3,134	2,065	757	718	810	16,612
2023	774	714	730	660	1,201	1,933	3,106	3,133	2,077	756	718	810	16,612
2024	770	736	730	654	1,199	1,942	3,070	3,147	2,087	754	721	802	16,612
2025	772	712	728	655	1,202	1,938	3,083	3,170	2,076	754	719	803	16,612

Commercial Building Efficiency

(megawatthours including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2006	68	59	72	69	90	107	148	154	108	80	66	66	1,087
2007	119	103	126	120	157	186	262	270	186	141	116	115	1,900
2008	178	158	183	179	230	274	393	386	280	209	170	171	2,810
2009	240	206	249	243	310	376	529	521	381	282	230	233	3,801
2010	304	264	322	312	395	483	673	672	483	358	297	299	4,861
2011	371	325	398	383	489	594	816	842	593	437	366	366	5,980
2012	444	402	472	453	590	698	985	1,013	700	528	434	430	7,149
2013	529	454	547	532	688	811	1,167	1,173	821	623	509	505	8,359
2014	609	521	626	614	788	937	1,346	1,324	958	716	582	586	9,605
2015	607	522	630	615	783	951	1,337	1,316	962	712	582	590	9,605
2016	599	537	637	614	784	952	1,309	1,349	951	701	587	586	9,605
2017	598	521	638	612	792	949	1,310	1,362	953	704	585	582	9,605
2018	603	521	635	609	793	940	1,326	1,363	942	710	584	579	9,605
2019	608	521	629	612	791	932	1,341	1,348	943	716	585	581	9,605
2020	608	538	628	614	781	949	1,334	1,314	960	711	581	589	9,605
2021	601	522	636	616	781	955	1,329	1,329	954	707	587	590	9,605
2022	597	521	638	616	786	954	1,311	1,352	953	702	588	587	9,605
2023	598	521	638	612	792	949	1,310	1,362	953	704	585	582	9,605
2024	602	540	628	611	790	930	1,339	1,345	941	715	584	580	9,605
2025	609	521	626	614	788	937	1,346	1,324	958	716	582	586	9,605

Industrial Efficiency
(megawatthours including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2006	1,664	1,451	1,546	1,498	1,538	1,579	1,607	1,549	1,588	1,673	1,580	1,580	18,853
2007	2,506	2,176	2,308	2,252	2,314	2,358	2,419	2,320	2,368	2,521	2,367	2,370	28,280
2008	3,337	3,001	3,053	3,013	3,064	3,130	3,228	3,052	3,169	3,356	3,133	3,170	37,706
2009	4,177	3,624	3,843	3,780	3,815	3,941	4,039	3,827	3,979	4,189	3,944	3,976	47,132
2010	4,987	4,348	4,638	4,534	4,567	4,734	4,827	4,613	4,781	5,002	4,752	4,776	56,559
2011	5,815	5,074	5,414	5,269	5,347	5,529	5,614	5,412	5,581	5,834	5,538	5,557	65,986
2012	6,641	6,002	6,140	5,991	6,156	6,272	6,435	6,172	6,299	6,706	6,296	6,304	75,412
2013	7,531	6,529	6,888	6,789	6,948	7,041	7,291	6,926	7,113	7,571	7,085	7,125	84,838
2014	8,381	7,251	7,654	7,554	7,682	7,847	8,091	7,652	7,943	8,412	7,853	7,947	94,265
2015	8,353	7,247	7,685	7,559	7,631	7,883	8,078	7,653	7,958	8,378	7,888	7,952	94,265
2016	8,291	7,487	7,712	7,506	7,618	7,876	7,998	7,710	7,950	8,310	7,890	7,917	94,265
2017	8,321	7,253	7,731	7,492	7,688	7,896	8,033	7,743	7,942	8,364	7,899	7,902	94,265
2018	8,354	7,253	7,695	7,507	7,714	7,859	8,063	7,734	7,893	8,403	7,890	7,899	94,265
2019	8,368	7,255	7,653	7,544	7,720	7,824	8,101	7,696	7,904	8,412	7,873	7,916	94,265
2020	8,353	7,470	7,664	7,538	7,609	7,860	8,055	7,631	7,935	8,354	7,866	7,929	94,265
2021	8,312	7,247	7,729	7,557	7,611	7,891	8,045	7,689	7,969	8,336	7,919	7,960	94,265
2022	8,308	7,249	7,734	7,528	7,639	7,899	8,020	7,732	7,972	8,334	7,912	7,939	94,265
2023	8,321	7,253	7,731	7,492	7,688	7,896	8,033	7,743	7,942	8,364	7,899	7,902	94,265
2024	8,333	7,503	7,632	7,523	7,699	7,802	8,079	7,675	7,882	8,389	7,851	7,895	94,265
2025	8,381	7,251	7,654	7,554	7,682	7,847	8,091	7,652	7,943	8,412	7,853	7,947	94,265

Irrigation Efficiency Rewards
(megawatthours including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2006	3	3	4	73	1,021	1,802	1,778	1,415	839	585	121	29	7,674
2007	6	5	8	137	1,904	3,364	3,323	2,648	1,560	1,093	225	55	14,328
2008	9	8	13	209	2,931	5,079	5,106	4,032	2,389	1,667	344	83	21,869
2009	12	10	17	276	3,859	6,716	6,728	5,292	3,164	2,196	453	110	28,834
2010	14	12	20	331	4,620	8,097	8,063	6,340	3,796	2,633	543	132	34,601
2011	17	14	23	386	5,388	9,464	9,367	7,421	4,426	3,074	634	154	40,368
2012	19	17	26	442	6,130	10,832	10,700	8,527	5,022	3,518	726	176	46,134
2013	21	18	30	497	6,914	12,115	12,088	9,600	5,645	3,958	817	198	51,901
2014	24	20	33	552	7,730	13,393	13,463	10,631	6,299	4,396	907	220	57,668
2015	24	20	33	552	7,719	13,433	13,457	10,584	6,328	4,393	906	219	57,668
2016	24	21	33	552	7,697	13,520	13,381	10,602	6,323	4,391	906	219	57,668
2017	24	20	33	552	7,674	13,545	13,364	10,633	6,302	4,395	907	220	57,668
2018	24	20	33	553	7,663	13,540	13,376	10,658	6,277	4,397	907	220	57,668
2019	24	20	33	553	7,682	13,461	13,431	10,667	6,273	4,398	907	220	57,668
2020	24	21	33	552	7,719	13,433	13,456	10,584	6,328	4,393	906	219	57,668
2021	24	20	33	551	7,699	13,496	13,438	10,567	6,326	4,389	906	219	57,668
2022	24	20	33	552	7,697	13,520	13,381	10,602	6,323	4,391	906	219	57,668
2023	24	20	33	552	7,674	13,545	13,364	10,633	6,302	4,395	907	220	57,668
2024	24	21	33	553	7,682	13,461	13,431	10,667	6,273	4,397	907	220	57,668
2025	24	20	33	552	7,730	13,393	13,463	10,631	6,299	4,396	907	220	57,668

Energy Efficiency Programs—Total
(megawatthours including losses)

Energy Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2006	1,857	1,625	1,738	1,745	2,838	3,795	4,024	3,613	2,863	2,457	1,880	1,803	30,240
2007	2,826	2,464	2,627	2,675	4,678	6,396	6,784	6,030	4,643	3,944	2,890	2,743	48,702
2008	3,791	3,424	3,501	3,630	6,644	9,156	9,798	8,572	6,559	5,494	3,897	3,704	68,170
2009	4,774	4,158	4,432	4,591	8,522	11,890	12,673	11,053	8,444	7,004	4,947	4,677	87,165
2010	5,736	5,020	5,382	5,542	10,248	14,381	15,281	13,377	10,203	8,413	5,989	5,654	105,226
2011	6,718	5,887	6,317	6,480	12,024	16,868	17,866	15,756	11,971	9,847	7,015	6,614	123,362
2012	7,701	6,991	7,206	7,393	13,805	19,298	20,509	18,140	13,641	11,335	8,013	7,534	141,567
2013	8,765	7,632	8,114	8,400	15,616	21,692	23,273	20,494	15,433	12,821	9,051	8,541	159,832
2014	9,785	8,505	9,040	9,375	17,402	24,114	25,983	22,776	17,276	14,278	10,061	9,555	178,151
2015	9,759	8,502	9,074	9,382	17,339	24,189	25,964	22,728	17,316	14,239	10,093	9,565	178,151
2016	9,689	8,783	9,108	9,335	17,300	24,274	25,798	22,789	17,286	14,157	10,099	9,530	178,151
2017	9,716	8,508	9,132	9,316	17,355	24,323	25,814	22,870	17,274	14,220	10,109	9,513	178,151
2018	9,753	8,508	9,095	9,324	17,372	24,273	25,853	22,894	17,207	14,265	10,102	9,505	178,151
2019	9,771	8,508	9,047	9,363	17,395	24,161	25,948	22,862	17,209	14,280	10,086	9,520	178,151
2020	9,757	8,769	9,050	9,358	17,314	24,162	25,933	22,699	17,288	14,213	10,069	9,540	178,151
2021	9,713	8,503	9,125	9,384	17,294	24,265	25,913	22,744	17,313	14,191	10,129	9,577	178,151
2022	9,703	8,504	9,132	9,359	17,326	24,302	25,829	22,819	17,314	14,183	10,124	9,555	178,151
2023	9,716	8,508	9,132	9,316	17,355	24,323	25,814	22,870	17,274	14,220	10,109	9,513	178,151
2024	9,729	8,800	9,024	9,340	17,371	24,135	25,919	22,834	17,183	14,255	10,063	9,497	178,151
2025	9,785	8,505	9,040	9,375	17,402	24,114	25,983	22,776	17,276	14,278	10,061	9,555	178,151

ENERGY STAR® Homes Northwest
(megawatts including losses)

Peak Demand Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2006	0	0	0	0	1	1	2	2	1	0	0	0	2
2007	1	1	1	1	1	2	2	3	2	1	1	1	3
2008	1	1	1	1	1	2	3	3	2	1	1	1	3
2009	1	1	1	1	2	3	4	4	3	1	1	1	4
2010	1	1	1	1	2	3	5	5	4	1	1	1	5
2011	2	2	1	1	2	4	6	6	4	2	1	2	6
2012	2	2	2	2	3	5	7	7	5	2	2	2	7
2013	2	2	2	2	3	5	8	8	6	2	2	2	8
2014	2	2	2	2	4	6	9	10	6	2	2	2	10
2015	2	2	2	2	4	6	9	10	6	2	2	2	10
2016	2	2	2	2	4	6	9	9	6	2	2	2	9
2017	2	2	2	2	4	6	9	9	6	2	2	2	9
2018	2	2	2	2	4	6	9	9	6	2	2	2	9
2019	2	2	2	2	4	6	9	9	7	2	2	2	9
2020	2	2	2	2	4	6	9	10	6	2	2	2	10
2021	2	2	2	2	4	6	9	9	6	2	2	2	9
2022	2	2	2	2	4	6	9	9	6	2	2	2	9
2023	2	2	2	2	4	6	9	9	6	2	2	2	9
2024	2	2	2	2	4	6	9	9	7	2	2	2	9
2025	2	2	2	2	4	6	9	10	6	2	2	2	10

Commercial Building Efficiency
(megawatts including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	1	1	1	1	0	0	0	1
2008	0	0	1	1	1	1	1	1	1	1	0	0	1
2009	1	1	1	1	1	1	1	1	1	1	1	1	1
2010	1	1	1	1	1	1	2	2	1	1	1	1	2
2011	1	1	1	1	1	2	2	2	2	1	1	1	2
2012	1	1	1	1	2	2	3	3	2	2	1	1	3
2013	1	1	2	2	2	2	3	3	2	2	1	1	3
2014	2	2	2	2	2	3	4	4	3	2	2	2	4
2015	2	2	2	2	2	3	4	4	3	2	2	2	4
2016	2	2	2	2	2	3	4	4	3	2	2	2	4
2017	2	2	2	2	2	3	4	4	3	2	2	2	4
2018	2	2	2	2	2	3	4	4	3	2	2	2	4
2019	2	2	2	2	2	3	4	4	3	2	2	2	4
2020	2	2	2	2	2	3	4	4	3	2	2	2	4
2021	2	2	2	2	2	3	4	4	3	2	2	2	4
2022	2	2	2	2	2	3	4	4	3	2	2	2	4
2023	2	2	2	2	2	3	4	4	3	2	2	2	4
2024	2	2	2	2	2	3	4	4	3	2	2	2	4
2025	2	2	2	2	2	3	4	4	3	2	2	2	4

Industrial Efficiency
(megawatts including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2006	2	2	2	2	2	2	2	2	2	3	2	2	3
2007	4	4	3	3	3	4	4	3	4	4	4	4	4
2008	5	5	5	5	5	5	5	5	5	5	5	5	5
2009	6	6	6	6	6	6	6	6	6	6	6	6	6
2010	7	7	7	7	7	7	7	7	7	7	7	7	7
2011	9	8	8	8	8	9	8	8	9	9	9	8	9
2012	10	10	9	9	9	10	10	9	10	10	10	9	10
2013	11	11	10	10	10	11	11	10	11	11	11	11	11
2014	12	12	11	12	11	12	12	11	12	12	12	12	12
2015	12	12	11	12	11	12	12	11	12	12	12	12	12
2016	12	12	12	12	11	12	12	12	12	12	12	12	12
2017	12	12	12	12	12	12	12	12	12	13	12	12	13
2018	12	12	11	12	12	12	12	12	12	13	12	12	13
2019	12	12	11	12	11	12	12	11	12	12	12	12	12
2020	12	12	11	12	11	12	12	11	12	12	12	12	12
2021	12	12	12	12	11	12	12	11	12	12	12	12	12
2022	12	12	12	12	11	12	12	12	12	12	12	12	12
2023	12	12	12	12	12	12	12	12	12	13	12	12	13
2024	12	12	11	12	11	12	12	11	12	12	12	12	12
2025	12	12	11	12	11	12	12	11	12	12	12	12	12

Irrigation Efficiency Rewards
(megawatts including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2006	0	0	0	0	2	4	4	3	2	1	0	0	4
2007	0	0	0	0	4	7	7	6	3	2	1	0	7
2008	0	0	0	0	6	11	11	9	5	4	1	0	11
2009	0	0	0	1	8	15	14	11	7	5	1	0	15
2010	0	0	0	1	10	18	17	14	8	6	1	0	18
2011	0	0	0	1	12	21	20	16	10	7	1	0	21
2012	0	0	0	1	13	24	23	18	11	8	2	0	24
2013	0	0	0	1	15	27	26	21	13	8	2	0	27
2014	0	0	0	1	17	30	29	23	14	9	2	0	30
2015	0	0	0	1	17	30	29	23	14	9	2	0	30
2016	0	0	0	1	17	30	29	23	14	9	2	0	30
2017	0	0	0	1	17	30	29	23	14	9	2	0	30
2018	0	0	0	1	17	30	29	23	14	9	2	0	30
2019	0	0	0	1	16	30	29	23	14	9	2	0	30
2020	0	0	0	1	17	30	29	23	14	9	2	0	30
2021	0	0	0	1	17	30	29	23	14	9	2	0	30
2022	0	0	0	1	17	30	29	23	14	9	2	0	30
2023	0	0	0	1	17	30	29	23	14	9	2	0	30
2024	0	0	0	1	16	30	29	23	14	9	2	0	30
2025	0	0	0	1	17	30	29	23	14	9	2	0	30

Energy Efficiency Programs—Total
(megawatts including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2006	3	3	3	3	5	8	8	7	6	4	3	3	8
2007	5	5	4	5	9	13	14	12	9	7	5	5	14
2008	6	6	6	6	13	19	20	18	13	10	7	6	20
2009	8	8	7	8	17	25	26	23	17	13	9	8	26
2010	10	9	9	10	20	30	32	28	21	15	11	10	32
2011	11	11	11	12	23	35	37	33	25	18	13	11	37
2012	13	13	12	13	27	41	43	38	28	21	14	13	43
2013	15	14	14	15	30	45	48	43	32	23	16	15	48
2014	17	16	15	17	34	50	54	47	35	26	18	16	54
2015	17	16	15	17	34	51	54	47	35	26	18	16	54
2016	17	16	16	17	34	51	54	48	36	26	18	16	54
2017	17	16	16	17	34	51	54	48	36	26	18	16	54
2018	17	16	16	17	34	51	54	48	35	26	18	16	54
2019	17	16	15	17	34	51	54	48	35	26	18	16	54
2020	17	16	15	17	34	51	54	47	35	26	18	16	54
2021	17	16	16	17	34	51	54	47	36	26	18	16	54
2022	17	16	16	17	34	51	54	48	36	26	18	16	54
2023	17	16	16	17	34	51	54	48	36	26	18	16	54
2024	16	16	15	17	34	51	54	48	35	26	18	16	54
2025	17	16	15	17	34	50	54	47	35	26	18	16	54

Demand Response Programs

A/C Cool Credit

(megawatts including losses)

Peak Demand Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2006	0	0	0	0	0	5	5	5	0	0	0	0	5
2007	0	0	0	0	0	9	14	18	0	0	0	0	18
2008	0	0	0	0	0	23	27	32	0	0	0	0	32
2009	0	0	0	0	0	36	41	45	0	0	0	0	45
2010	0	0	0	0	0	45	45	45	0	0	0	0	45
2011	0	0	0	0	0	45	45	45	0	0	0	0	45
2012	0	0	0	0	0	45	45	45	0	0	0	0	45
2013	0	0	0	0	0	45	45	45	0	0	0	0	45
2014	0	0	0	0	0	45	45	45	0	0	0	0	45
2015	0	0	0	0	0	45	45	45	0	0	0	0	45
2016	0	0	0	0	0	45	45	45	0	0	0	0	45
2017	0	0	0	0	0	45	45	45	0	0	0	0	45
2018	0	0	0	0	0	45	45	45	0	0	0	0	45
2019	0	0	0	0	0	45	45	45	0	0	0	0	45
2020	0	0	0	0	0	45	45	45	0	0	0	0	45
2021	0	0	0	0	0	45	45	45	0	0	0	0	45
2022	0	0	0	0	0	45	45	45	0	0	0	0	45
2023	0	0	0	0	0	45	45	45	0	0	0	0	45
2024	0	0	0	0	0	45	45	45	0	0	0	0	45
2025	0	0	0	0	0	45	45	45	0	0	0	0	45

Irrigation Peak Rewards

(megawatts including losses)

Peak Demand Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2006	0	0	0	0	0	35	32	26	0	0	0	0	35
2007	0	0	0	0	0	35	32	26	0	0	0	0	35
2008	0	0	0	0	0	35	32	26	0	0	0	0	35
2009	0	0	0	0	0	35	32	26	0	0	0	0	35
2010	0	0	0	0	0	35	32	26	0	0	0	0	35
2011	0	0	0	0	0	35	32	26	0	0	0	0	35
2012	0	0	0	0	0	35	32	26	0	0	0	0	35
2013	0	0	0	0	0	35	32	26	0	0	0	0	35
2014	0	0	0	0	0	35	32	26	0	0	0	0	35
2015	0	0	0	0	0	35	32	26	0	0	0	0	35
2016	0	0	0	0	0	35	32	26	0	0	0	0	35
2017	0	0	0	0	0	35	32	26	0	0	0	0	35
2018	0	0	0	0	0	35	32	26	0	0	0	0	35
2019	0	0	0	0	0	35	32	26	0	0	0	0	35
2020	0	0	0	0	0	35	32	26	0	0	0	0	35
2021	0	0	0	0	0	35	32	26	0	0	0	0	35
2022	0	0	0	0	0	35	32	26	0	0	0	0	35
2023	0	0	0	0	0	35	32	26	0	0	0	0	35
2024	0	0	0	0	0	35	32	26	0	0	0	0	35
2025	0	0	0	0	0	35	32	26	0	0	0	0	35

Demand Response Programs—Total
(megawatts including losses)

Peak Demand Reductions													
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2006	0	0	0	0	0	39	37	30	0	0	0	0	39
2007	0	0	0	0	0	44	46	44	0	0	0	0	46
2008	0	0	0	0	0	57	59	57	0	0	0	0	59
2009	0	0	0	0	0	71	73	71	0	0	0	0	73
2010	0	0	0	0	0	80	78	71	0	0	0	0	80
2011	0	0	0	0	0	80	78	71	0	0	0	0	80
2012	0	0	0	0	0	80	78	71	0	0	0	0	80
2013	0	0	0	0	0	80	78	71	0	0	0	0	80
2014	0	0	0	0	0	80	78	71	0	0	0	0	80
2015	0	0	0	0	0	80	78	71	0	0	0	0	80
2016	0	0	0	0	0	80	78	71	0	0	0	0	80
2017	0	0	0	0	0	80	78	71	0	0	0	0	80
2018	0	0	0	0	0	80	78	71	0	0	0	0	80
2019	0	0	0	0	0	80	78	71	0	0	0	0	80
2020	0	0	0	0	0	80	78	71	0	0	0	0	80
2021	0	0	0	0	0	80	78	71	0	0	0	0	80
2022	0	0	0	0	0	80	78	71	0	0	0	0	80
2023	0	0	0	0	0	80	78	71	0	0	0	0	80
2024	0	0	0	0	0	80	78	71	0	0	0	0	80
2025	0	0	0	0	0	80	78	71	0	0	0	0	80