Appendix A — Sales and Load Forecast

For the 2009 Integrated Resource Plan

December 2009

IDAHO POWER®
An IDACORP Company

Appendix A — Sales and Load Forecast

For the 2009 Integrated Resource Plan – December 2009

IDAHO POWER.
An IDACORP Company

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

INTRODUCTION

Idaho Power has prepared *Appendix A–Sales and Load Forecast* as an appendix to its *2009 Integrated Resource Plan* (IRP). The sales and load forecast is Idaho Power's best estimate of the future demand for electricity within the company's service area. The forecast covers the 20-year period from 2010 through 2029. For planning purposes, the future demand for electricity by customers in Idaho Power'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 based on variable weather evaluated in the 2009 IRP. The expected-case total load growth rate is 0.7 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 Idaho Power's service area.

Two additional load forecasts for Idaho Power's service area were prepared. These forecasts provide a range of possible load growths for the 2010–2029 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on statistical analyses 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 on weather conditions, two alternative scenarios were considered to address the load variability due to weather. A 70th percentile average load forecast and 90th percentile average 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 three-out-of-ten years (30 percent of the time). The 90th percentile load forecast assumes monthly loads that can be exceeded in one-out-of-ten years (10 percent of the time).

In the expected-case scenario, Idaho Power's total load is forecast to increase to 2,015 average megawatts (aMW) in the year 2029 from the 2010 forecast load of 1,797 aMW. The expected-case forecast total load growth rate averages 0.7 percent per year over the 20 years of the planning period (2010–2029). The number of Idaho Power retail customers increased from the December 2008 level of 485,655 customers to over 682,000 customers at year-end 2029. Idaho Power system peak load is forecast to grow to 4,445 megawatts (MW) in the year 2029 from the 2008 actual system peak of 3,214 MW. The highest system peak on record was 3,214 MW and occurred on Monday, June 30, 2008, at 3:00 p.m. In the expected-case scenario, Idaho Power system peak increases at an average growth rate of 1.5 percent per year over the 20 years of the planning period (2010–2029).

This year's economic forecast was based on a forecast of national and regional economic activity developed by Moody's Analytics, a national econometric consulting firm. Moody's Analytics June 2009 macroeconomic forecast strongly influenced *Appendix A–Sales and Load Forecast*. The national, state, metropolitan statistical area (MSA), and county econometric projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics were also used in development of *Appendix A–Sales and Load Forecast*.

Economic growth assumptions influence several of the individual class of service growth rates. The number of households in Idaho is projected to grow at an annual average rate of 1.3 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, incomes, employment projections, economic output, real retail electricity prices, and customer consumption patterns are 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 the assumptions is presented in the sections of this report pertaining to the individual sectors.

The future load impacts of implemented and committed Idaho Power energy efficiency demand-side management (DSM) programs are considered within *Appendix A–Sales and Load Forecast*. These programs and their expected impacts are addressed in more detail in Idaho Power's *Demand-Side Management 2008 Annual Report*. This report is Appendix B to the 2009 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- and low-growth scenarios provide boundaries on each side of the expected-case scenario and historical load variability potential on future load due to demographic, economic, and other non-weather-related influences. The 70^{th} percentile and 90^{th} percentile load forecast scenarios were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to more adverse weather conditions.

During the 20-year forecast horizon, there could be major changes in the electric utility industry, such as carbon legislation and fossil fuel market disequilibrium. The high degree of uncertainty associated with such changes is assumed to be reflected in the economic high and low load growth scenarios described above. However, due to the increasing probability of impending carbon legislation becoming law, the impact of carbon legislation on the load forecast was reflected in the forecast of retail electricity prices, which is a driver in the major sector sales forecasting models. The alternative sales and load scenarios of *Appendix A–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 the sales and load forecast is presented in Appendix A1 of this report.

2009 IRP SALES AND LOAD FORECAST

Average Load

The 2009 IRP average system load forecast is lower than the 2006 IRP average system load forecast in all years of the forecast period. The slowdown in the national and service-area economy caused load growth to slow dramatically. In addition, the significant increase in energy efficiency and demand response measures, combined with retail electricity prices that incorporate estimates of proposed carbon legislation, result in a decrease of forecast average loads. Significant factors and considerations that influenced the outcome of the 2009 IRP load forecast include the following.

- For the first time, the sales and load forecasts are influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales.
- Existing energy efficiency program performance is estimated and included in the sales and load forecast base, lowering the energy and peak demand forecast. However, the impact of demand response programs is accounted for in the load and resource balance. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C–Technical Appendix*.
- The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and will reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses) once continuous operation is reached in 2012.
- A collapse in the housing sector dramatically slowed the growth in the number of new households and residential customers being added to Idaho Power's service area. The number of commercial customers being added has also slowed dramatically as a result of the economic downturn. Both the residential and commercial customer forecasts were adjusted downward in the near-term to reflect the current housing slowdown and credit crisis. However, by 2012, residential and commercial customer growth is expected to recover, and customer additions are expected to be similar to the growth that occurred prior to the housing bubble in the 1993–2003 timeframe.
- The irrigation sales forecast is somewhat higher due to a substantial increase in weather-adjusted irrigation sales over the last two years (6 percent in 2007 and 8 percent in 2008). Higher farm commodity prices seem to be the primary reason behind the irrigation sales increase. Irrigators appear to have taken advantage of the commodities market by planting all available acreage. In addition, the conversion of hand line to electrically operated pivot irrigation systems may explain a part of the increased energy consumption. In recent years, the increased labor costs associated with moving hand lines and increased concerns for water conservation has triggered the substitution of labor with electrically operated pivots.
- There is uncertainty associated with the growth of new industrial and special contract customers. The forecast uncertainty is associated with the increasing number of entities that have contacted Idaho Power and expressed interest in locating their operations within Idaho Power's service area in conjunction with the uncertain magnitude of associated energy and peak-demand requirements. The current sales and load forecast reflects only those customers that have a very high probability of relocating to the service area or have made financial commitments and whose facilities are actually being constructed at this time. Therefore, the number of large customers that have contacted

Idaho Power and shown interest, but have not made commitments, are not included in the current sales and load forecast.

Peak-Hour Demands

Peak day temperatures and the growth in average loads drive the peak forecasting model regressions. The peak forecast results and comparisons with previous forecasts differ for a number of reasons that include the following:

- The 2009 IRP peak forecast reflects the increased expected peak demand of Idaho Power's newest special contract customer, Hoku Materials, located in Pocatello, Idaho.
- The 2009 IRP peak-demand forecast was adjusted downward to reflect the estimated impact of energy efficiency DSM programs that were selected for implementation since 2006. Energy efficiency programs are incorporated into the peak-demand forecast as the programs are committed and implemented.
- The 2009 IRP peak-demand forecast model no longer considers or adjusts for the impact of demand response programs. The demand response programs are included in the load and resource balance as a reduction in peak demand.
- 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.
- Recent historical peak data is added 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. In addition, new system peaks were reached in July 2007 and again in June 2008 and were incorporated into the peak forecast model.
- Idaho Power continues to use 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. The weighted average peak day temperature drivers are calculated over the 1978–2007 time period (the most recent 30 years).

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, Inc, (Micron Technology), Simplot Fertilizer Company (Simplot Fertilizer), Idaho National Laboratory (INL), Hoku Materials, and Raft River Rural Electric Cooperative, Inc. (Raft River)—the electric distribution utility serving Idaho Power's former customers in 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 the 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 in 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 2009 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 using 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 uses statistically derived peak day temperatures based on the most recent 30 years of climate data for each month. Peak loads for the INL, Micron Technology, Simplot Fertilizer, Hoku Materials, and Raft River are forecast based on historical analysis and contractual considerations.

The primary exogenous factors in the forecast are macroeconomic and demographic data. Moody's Analytics provides the macroeconomic forecasts. The national, state, MSA, and county economic and demographic projections are tailored to Idaho Power's service area using an economic database developed by an outside consultant. 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 drivers, impact long-term trends in electricity sales. Changes in relative fuel prices can also have significant impacts on the future demand for electricity. For the first time, the sales and load forecast is influenced by the estimated impact of proposed carbon legislation on retail electricity prices. The carbon-impacted retail electricity prices move significantly higher throughout the forecast period, reducing future electricity sales. Class level and economic-sector level regression models were used to identify the relationships between real historical electricity prices and historical electricity sales. The estimated coefficients from these models were used as drivers in the individual sales forecast models.

Short-term and long-term nominal electricity price increases are generated internally from Idaho Power financial models. Moody's Analytics 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.

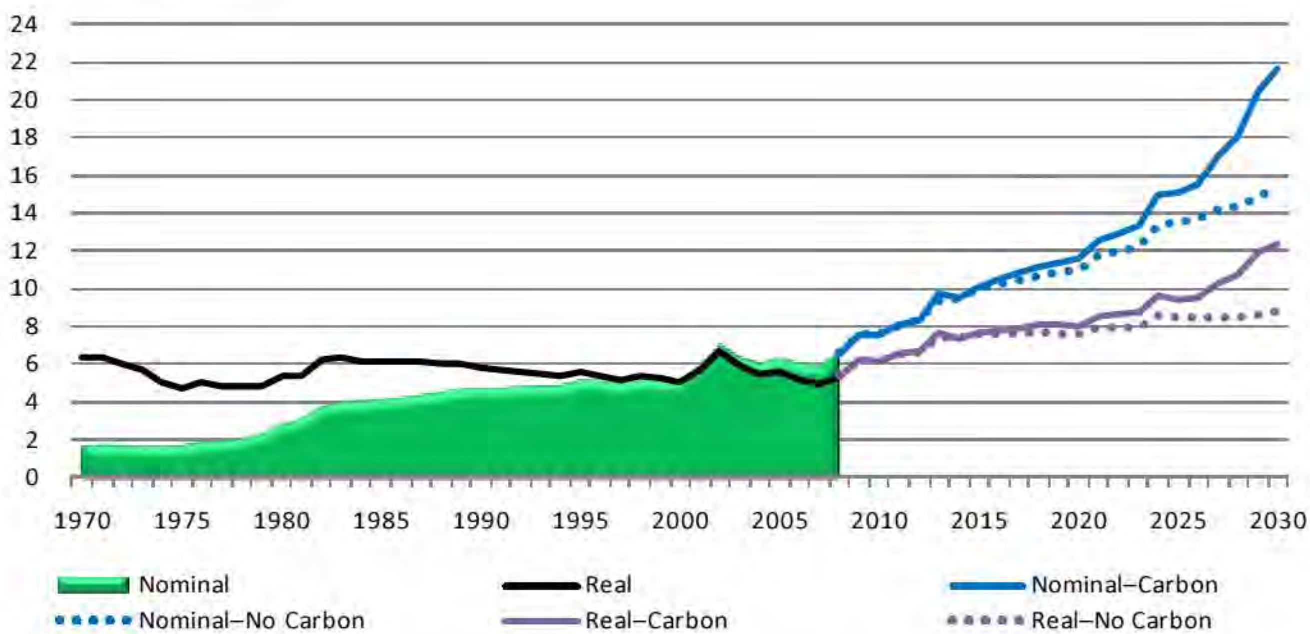
Table 1. Residential Fuel-Price Escalation (2009–2029)
(average annual percent change)

	Nominal	Real*
Electricity–Carbon	5.1%	3.3%
Electricity–No Carbon	3.4%	1.6%
Natural Gas	2.3%	0.5%

*adjusted for inflation

Figure 1 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1970–2008 and over the forecast period 2009–2029. Both nominal and real prices are shown. In the carbon scenario, nominal electricity prices are expected to slowly climb to 20 cents per kWh by the end of the forecast period in 2029. Real electricity prices (inflation-adjusted) in the carbon scenario are expected to increase over the forecast period at an average rate of 3.3 percent each year.

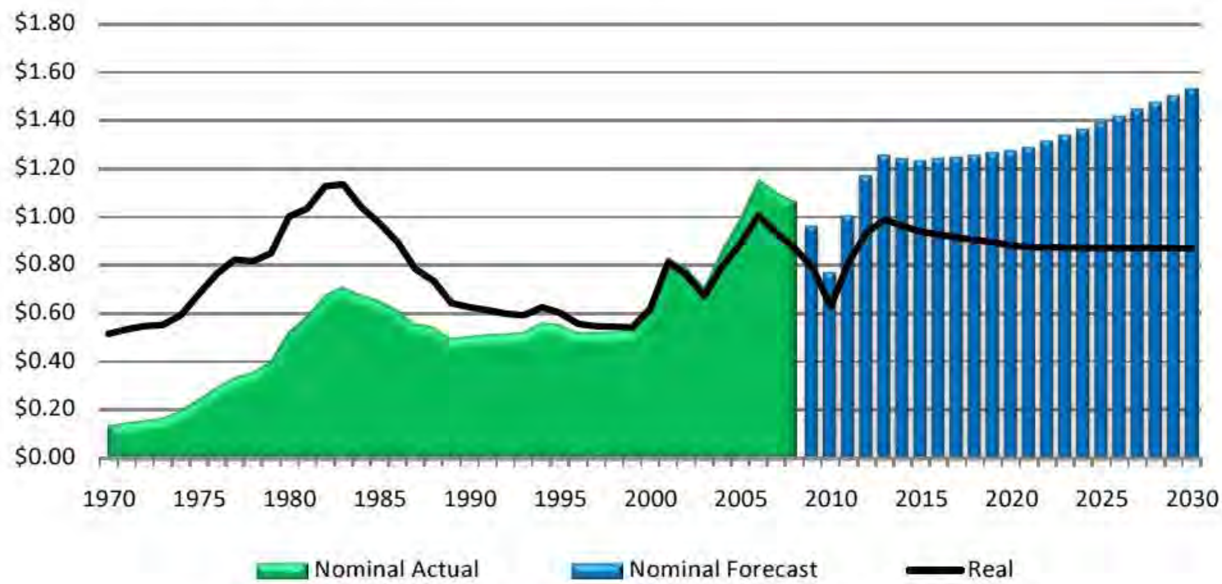
Figure 1. Forecasted Electricity Prices
(cents per kWh)



Electricity prices for Idaho Power customers moved significantly higher beginning in 2001 because of the Power Cost Adjustment (PCA) impact on rates. Prior to 2001, Idaho Power's electricity prices were historically quite stable. Over the 1990–2000 period, electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent each year.

Figure 2 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1970–2008. 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, 2005, and 2006. Natural gas prices are expected to move downward in 2009 and 2010, reflecting the collapse in natural gas prices in 2009. After bottoming in 2010, nominal natural gas prices are expected to rise rapidly through 2013 and then slowly rise through the remainder of the forecast period. Natural gas prices at the end of the forecast period are expected to be about 40 percent higher than 2008, growing at an average rate of 2.3 percent per year over the forecast period (2009–2029). Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0.5 percent each year.

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



If future electricity price increases continue to outpace natural gas price increases, as expected in this forecast, the operating costs of space heating and water heating with natural gas will become even more advantageous when compared to that of electricity. This could result in lowering the winter demand for electricity.

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 national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power'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 depending on 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 HDD are assumed in winter and the lowest recorded levels of CDD and GDD, 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 1978–2007 time period (the most recent 30 years) was 1,035. The 70th percentile HDD is 1,074 and would be exceeded in three-out-of-ten years. The 90th percentile HDD is 1,291 and would be exceeded in one-out-of-ten years. The 100th percentile HDD (the coldest December over the 30 years) 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 dependent on weather, and these two scenarios allow careful examination of load variability and how it may impact future 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 an entire year, would be much less probable. It is the monthly forecast numbers that are being evaluated for resource planning, and caution should be used in interpreting the meaning of the annual average load figures being reported and graphed for the 70th percentile or 90th percentile forecasts.

Table 2 summarizes the load scenarios prepared for the 2009 IRP. Three average load scenarios were prepared based on a statistical analysis of the 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 on a statistical analysis of historical peak day temperatures. The probability associated with each individual peak-demand scenario is also indicated in Table 2.

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 analysis of resource requirements is based on the 70th percentile average-load forecast coupled with the 95th percentile peak-demand forecast to provide a more adverse representation of average load and peak demand to be considered. In other Idaho Power planning, such as the preparation of the financial forecast or the operating plan, the expected-case (50th percentile) average-load forecast and the 90th percentile peak-demand forecast are typically used.

Load Forecasts Based on Economic Uncertainty

The expected-case load forecast is based on the most recent economic forecast for Idaho Power's service area and represents Idaho Power's most probable outcome for load growth during the planning period. The expected-case load forecast reflects the full integration of existing energy efficiency DSM program effects as a reduction to the average-load forecast. In addition, higher retail electricity prices resulting from carbon legislation also serve to slow the growth in electricity sales long term.

Two additional load forecasts for the Idaho Power service area were prepared. The forecasts provide a range of possible load growths for the 2010–2029 planning period due to variable economic and demographic conditions. The high economic growth and low economic growth scenarios were prepared based on 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 past 25 years (1984–2008).

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 1984 and 2008. 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 (1984–2008). The high- and low-case load forecasts also reflect the full integration of existing energy efficiency DSM program effects as a reduction to the average load forecasts. However, impacts from carbon legislation do not influence the high- and low-case load forecasts at this time.

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 one-year, five-year, and 10-year time periods are also shown in Table 3.

Table 3. Forecast Probabilities

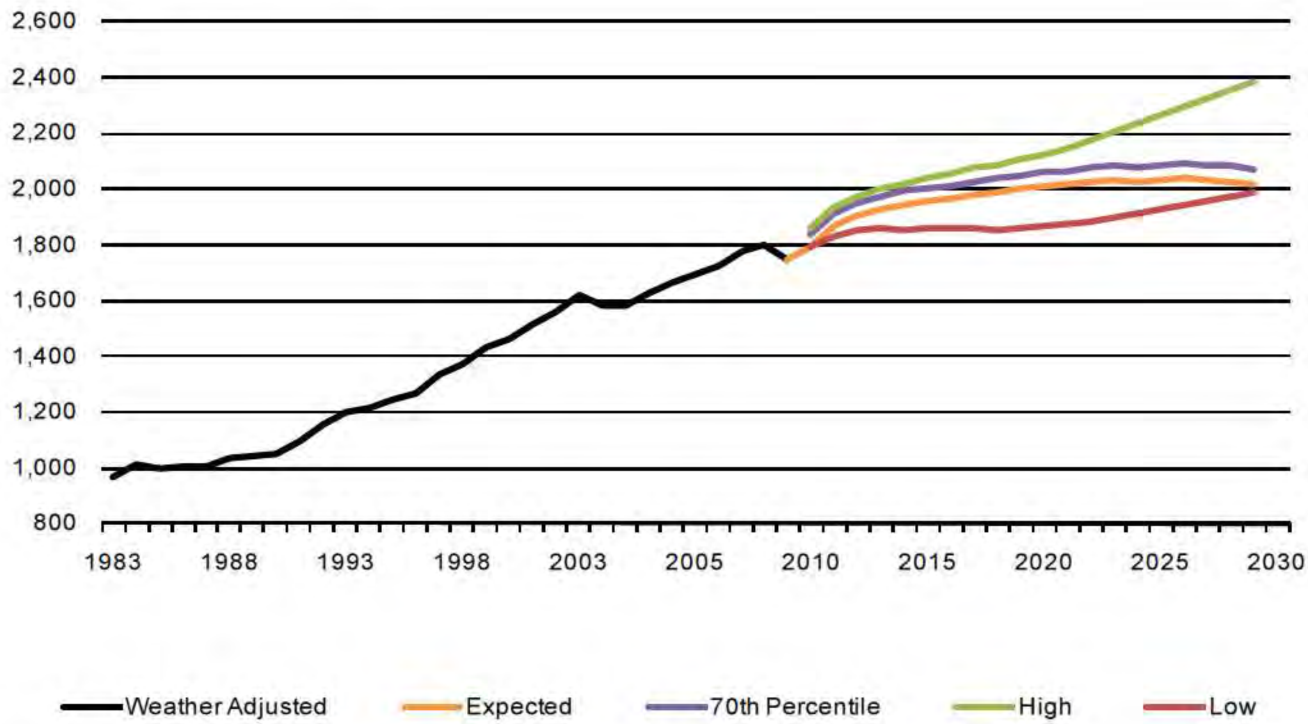
Probability of Exceeding				
Scenario	1-year	5-year	10-year	20-year
Low Growth	90%	90%	90%	90%
Expected Case	50%	50%	50%	50%
High Growth	10%	10%	10%	10%
Probability of Occurrence				
Scenario	1-year	5-year	10-year	20-year
Low Growth	26%	26%	26%	26%
Expected Case	48%	48%	48%	48%
High Growth	26%	26%	26%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

Firm load includes the sum of residential, commercial, industrial, irrigation, as well as special contracts (excluding Astaris), and Raft River. Idaho Power firm load projections are reported in Table 4 and pictured in Figure 3. The expected-case firm load forecast growth rate averages 0.7 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 0.6 percent per year throughout the forecast period. The high scenario projects load growth of 1.6 percent per year. Idaho Power 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's historical experience.

Table 4. System/Firm Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
High	1,752	2,020	2,105	2,389	1.6%
Expected	1,752	1,857	2,002	2,015	0.7%
Low	1,752	1,876	1,862	1,991	0.6%

Figure 3. Forecasted Firm Load
(aMW)



This page left blank intentionally.

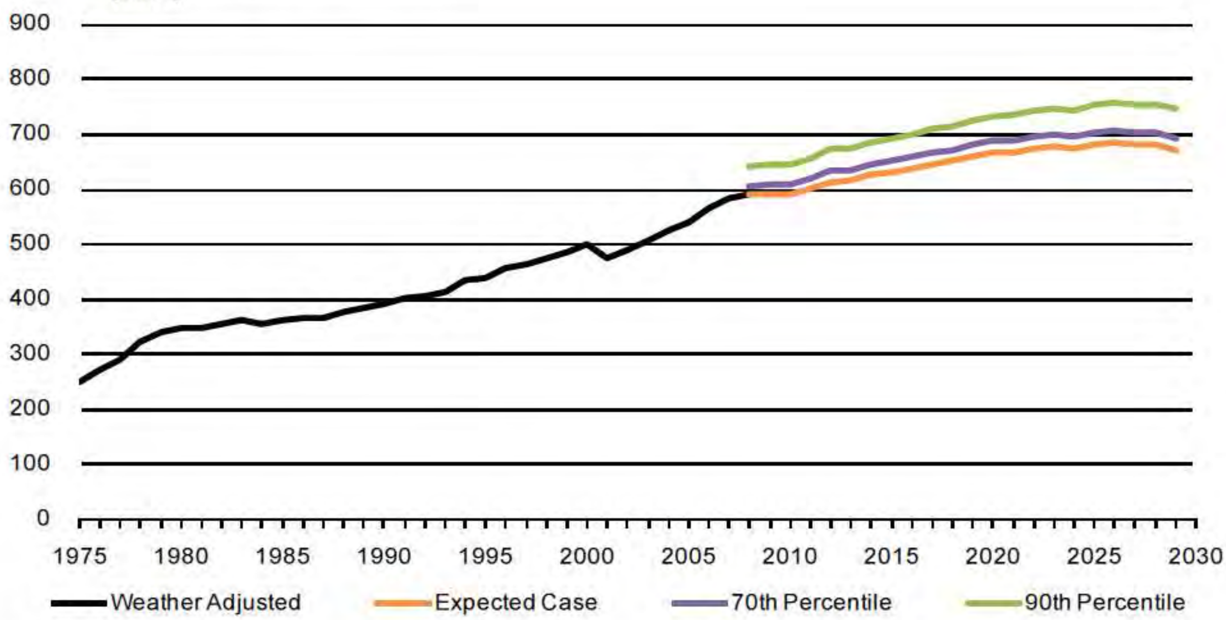
RESIDENTIAL

The expected-case residential load is forecast to increase from 590 aMW in 2009 to 670 aMW in 2029, an average annual compound growth rate of 0.6 percent. In the 70th percentile scenario residential load is forecast to increase from 608 aMW in 2009 to 694 aMW in 2029, nearly 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
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	645	687	725	747	0.7%
70th Percentile	608	647	681	694	0.7%
Expected Case	590	627	659	670	0.6%

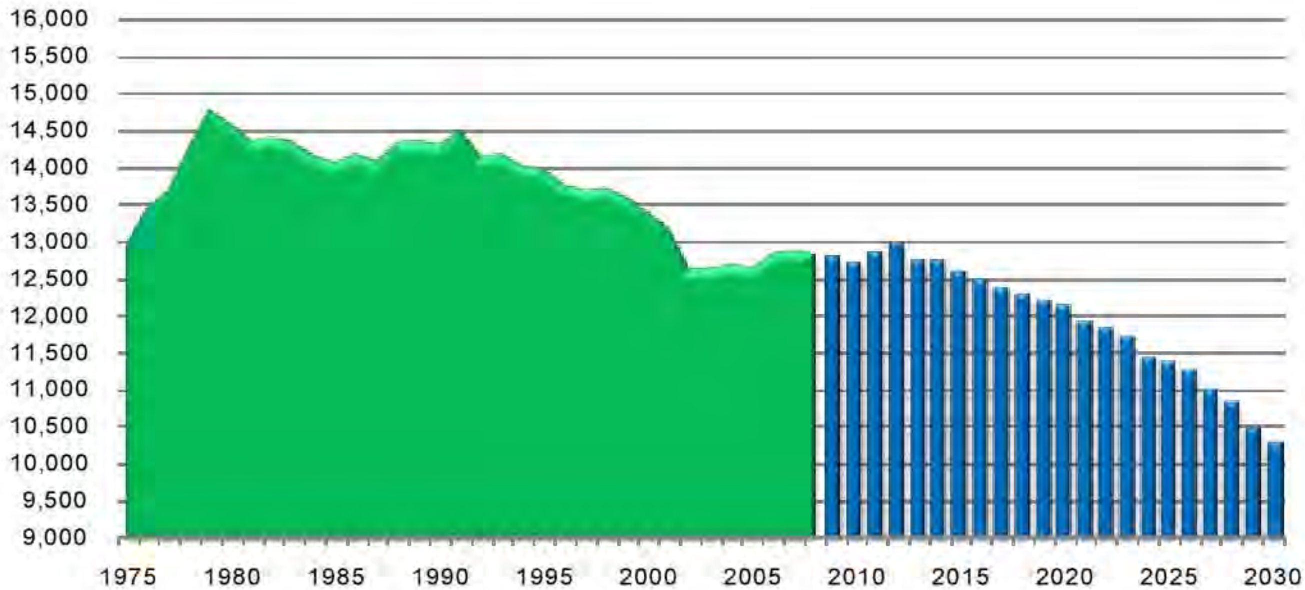
Figure 4. Forecasted Residential Load
(aMW)



Sales to residential customers made up 24 percent of Idaho Power's system sales in 1970 and 36 percent of system sales in 2008. The residential customer proportion of system sales is forecast to be approximately 36 percent in 2029. There were 404,373 residential customers as of December 2008. The number of residential customers is projected to increase to approximately 563,000 by December 2029. The relative customer proportions of the total Idaho Power electricity sales are shown in Figure 18.

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 13,150 kWh in 2001. In 2002 and 2003, residential-use-per-customer dropped dramatically—over 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 June 2003 and a recovery in the service-area economy caused residential-use-per-customer to stabilize and rise through 2007. However, the recession in 2008 and 2009 slowed the growth in residential-use-per-customer. The average sales per residential customer are expected to decline to approximately 10,500 kWh per year in 2029. Average annual sales per residential customer are shown in Figure 5.

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



The residential-use-per-customer forecast is based on a forecast of the number of residential customers and an econometric analysis of residential-sector sales. The number of residential customers being added each year is a direct function of the number of new service area households as derived from Moody's Analytics May 2009 forecast of county housing stock and demographic data. The customer forecast for 2010–2029 shows an average annual growth rate of 1.7 percent.

The residential-sales forecast equation considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime), CDD (summertime), the number of service area households as derived from Moody's Analytics forecasts of county housing stock, the real price of electricity, and the real price of natural gas. The forecast of residential-use-per-customer is arrived at by dividing the residential sales forecast, which includes the impact of forecasted DSM, by the residential-customer forecast.

COMMERCIAL

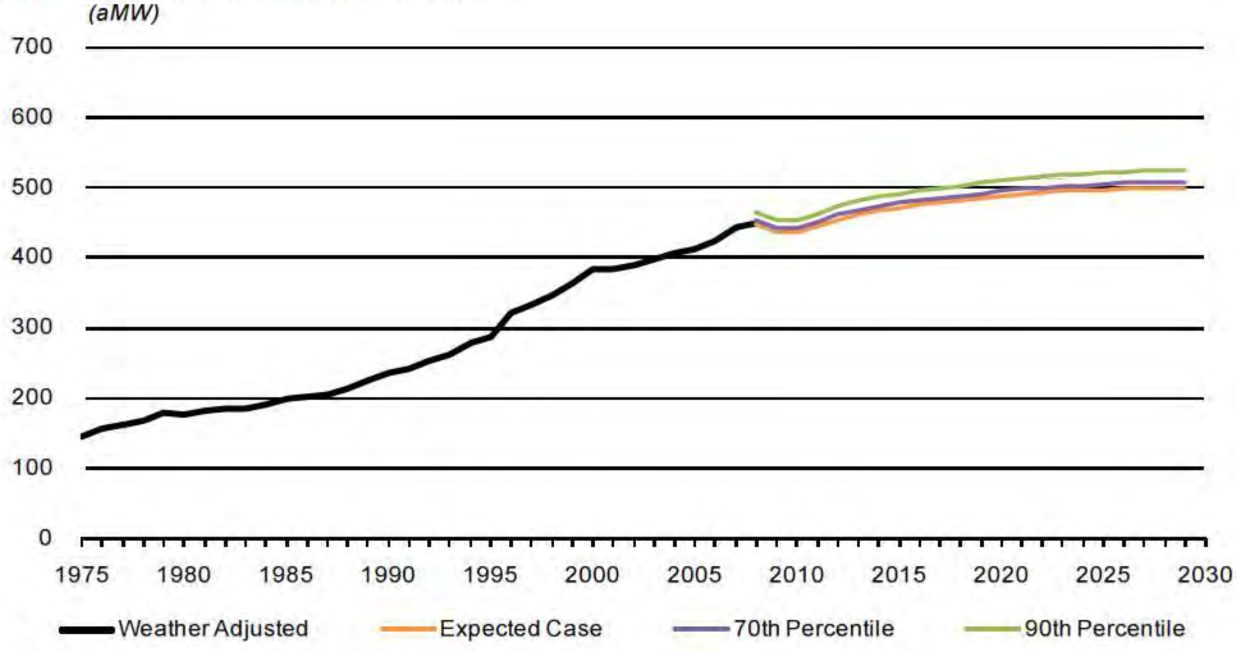
The commercial category is primarily made up of Idaho Power's Small General Service and Large General Service customers. Other schedules that are considered part of the commercial category are Unmetered General Service, Street Lighting Service, Traffic Control Signal Lighting Service, and Dusk-to-Dawn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

In the expected-case scenario, commercial load is projected to increase from 437 aMW in 2009 to 500 aMW in 2029. The average annual compound growth rate of commercial load is 0.7 percent during the forecast period. As summarized in Table 6, the commercial load in the 70th percentile scenario is projected to increase from 442 aMW in 2009 to 509 aMW in 2029. The commercial load forecasts are illustrated in Figure 6.

Table 6. Commercial Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	453	488	507	526	0.7%
70th Percentile	442	475	492	509	0.7%
Expected Case	437	469	486	500	0.7%

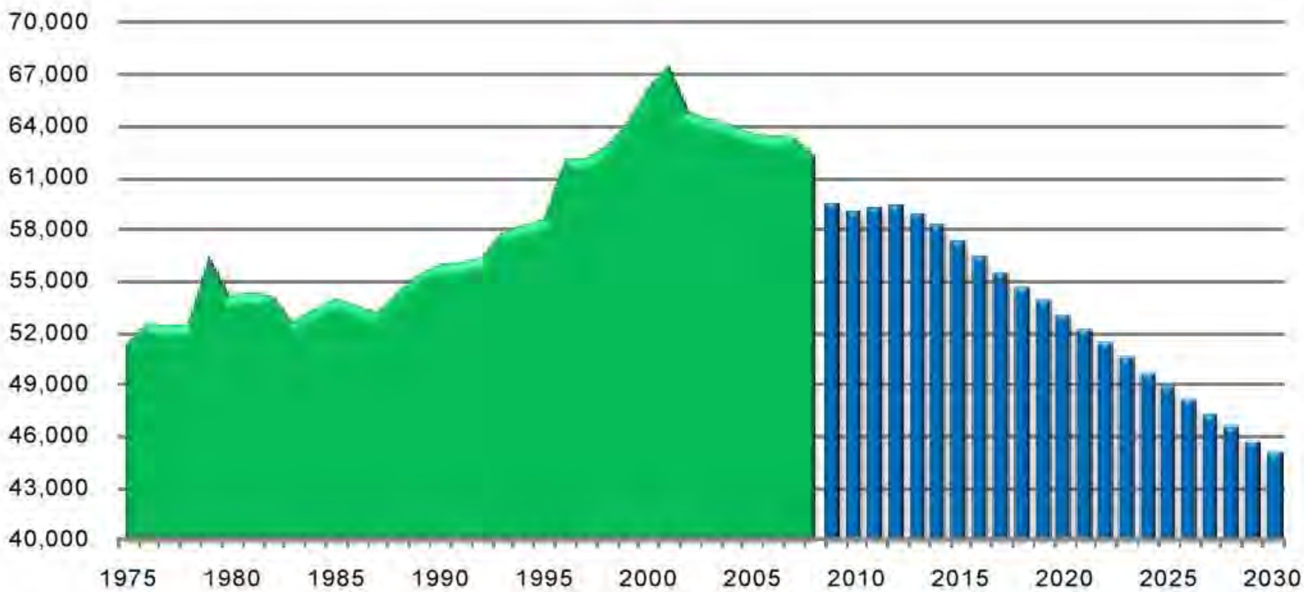
Figure 6. Forecasted Commercial Load
(aMW)



As of December 2008, Idaho Power had 64,125 commercial customers. The number of commercial customers is expected to increase at an average annual growth rate of 2.1 percent, reaching 96,500 customers by 2029. Commercial customers consumed nearly 17 percent of Idaho Power system sales in 1970 and 27 percent of system sales in 2008. The commercial customer proportion of system sales is projected to increase to 27 percent of system sales by 2029. The relative customer proportions of Idaho Power's total electricity sales are shown in Figure 18.

The average consumption per commercial customer increased to a record 67,400 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 June 2003 and a recovery in the service area economy slowed the rate of decline in commercial-use-per-customer through 2007. However, a severe recession in 2008 and 2009 caused commercial-use-per-customer to drop considerably. After flattening over the time period from 2009–2012, commercial-use-per-customer is projected to continue its downward trend. The primary reasons for the decline are higher retail electricity prices due to generating plant additions, carbon regulation, and significant DSM impacts on energy sales. The average consumption per commercial customer is expected to decrease to approximately 46,000 kWh per customer in 2029. Average annual use per commercial customer is shown in Figure 7.

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



The commercial-use-per-customer forecast is based on a forecast of the number of commercial customers and an econometric analysis of commercial sector sales. The number of commercial customers being added each year is a direct function of the number of new residential customers being added. Additionally, the number of residential customers being added is a direct function of the number of new service area households as derived from Moody's Analytics May 2009 economic forecast of county housing stock and demographic information. The commercial-customer forecast for 2010–2029 shows an average annual growth rate of 2.1 percent.

The commercial-sales forecast equation considers several factors affecting electricity sales to the commercial sector. Commercial sales are a function of HDD (wintertime), CDD (summertime), the number of service area households and service area employment as derived from Moody's Analytics forecasts, and the real price of electricity. The commercial-use-per-customer forecast is arrived at by dividing the commercial sales forecast, including the impacts of DSM, by the commercial customer forecast.

IRRIGATION

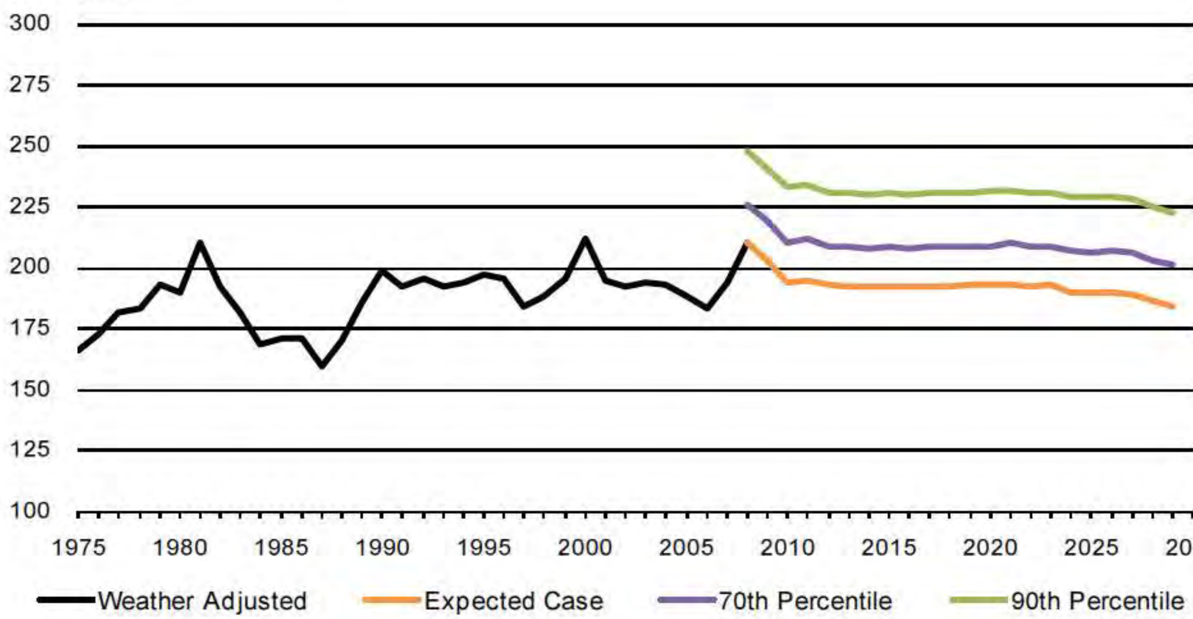
The irrigation category is made up of agricultural irrigation service customers. Service under this schedule is applicable to power and energy supplied to agricultural-use customers at one point-of-delivery for operating water pumping or water delivery systems to irrigate agricultural crops or pasturage.

Throughout the forecasted period, the expected-case irrigation load is forecast to slowly decline from 203 aMW in 2009 to 184 aMW in 2029, an average annual compound growth rate of –0.5 percent. The expected-case, 70th percentile, and 90th percentile scenarios forecast declining growth in irrigation load over the 2009–2029 time period. In the 70th percentile scenario, irrigation load is projected to be 219 aMW in 2009 and 201 aMW in 2029. 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 being put into production that was experienced by the agricultural economy in the mid-1980s.

Table 7. Irrigation Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	241	230	231	223	–0.4%
70th Percentile	219	208	209	201	–0.4%
Expected Case	203	192	193	184	–0.5%

Figure 8. Forecasted Irrigation Load
(aMW)



It is important to understand that annual average-load figures being reported in Table 7 and graphed in Figure 8 are calculated using the 8,760 hours of a typical year. In the highly seasonal irrigation sector, over 97 percent of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can exceed 900 MW. In a normal July, irrigation pumping accounts for roughly

25 percent of the energy generated during the hour of the annual system peak and 30 percent of the energy generated during the July calendar-month for general business sales. Note that it is the monthly forecast load 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 to not use electricity in 2001. The voluntary load-reduction program was effective and resulted in a 30 percent, or approximately 500,000 megawatt-hours (MWh) reduction in 2001 irrigation sales. 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. Any future reductions to irrigation load are assumed to occur through DSM programs or other natural economic pressures.

The 2009 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature, precipitation, spring rainfall, *Moody's Gross Produce: Farms, for Idaho,* and the real 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, Idaho Power experienced an increase in electricity-using irrigated acres of 1,179,000 acres. This growth in total electricity-using irrigated acres represented approximately a 2.8 percent average annual compound rate of growth. Idaho Power projects no growth in irrigated acres in the service area and limited growth in sprinkler irrigation or conversion to sprinkler irrigation.

Irrigation sales represented over 15 percent of weather-normalized Idaho Power system sales in 1970. Irrigation sales reached a maximum proportion of nearly 20 percent of Idaho Power system sales in 1975–1977. In 2008, the irrigation proportion of system sales was 13 percent due to the very rapid growth in other customer classes. By 2029, irrigation customers are projected to consume 10 percent of Idaho Power system sales. The customer load proportions are shown in Figure 18.

In 1970, Idaho Power had about 7,300 active irrigation accounts. By 2008, the number of active irrigation accounts had increased to 17,428 and is projected to be over 23,000 irrigation accounts at the end of the planning period in 2029.

Since 1988, Idaho Power has experienced some growth in the number of irrigation customers, but very little, if any, growth in total electricity sales to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler-irrigated land. However, the conversion rate is low, and 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 for furrow irrigation is gravity-drawn from canals and not pumped from deep groundwater wells. In 2007 and 2008, electricity sales (weather-adjusted) increased by 6 percent and over 8 percent, respectively, over each prior year. However, this is not completely unexpected because both 2007 and 2008 irrigation sales were below the annual sales numbers for years 1992 and 2000. Part of the increase can be explained by the gradual increase in the planting of more water-intensive crops, such as alfalfa and corn, to meet the higher demand for feed associated with the growing dairy industry in Idaho. Also, 2008 saw unprecedented crop prices for almost all crops, causing customers to irrigate all of the acreage that was available in 2008.

Bell Rapids, a large high-lift cooperative irrigation company that irrigated about 25,000 acres from 1970 to 2004, was Idaho Power's largest irrigation customer. The Bell Rapids combined accounts included more than 40 individual irrigation service points that accounted for approximately 3 to 4 percent of

Idaho Power's annual irrigation sales. In early 2005, the State of Idaho purchased the water rights from Bell Rapids, which resulted in the loss of Bell Rapids as an irrigation customer. Prior to 2005, Bell Rapids has consumed, on average, 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.

This page left blank intentionally.

INDUSTRIAL

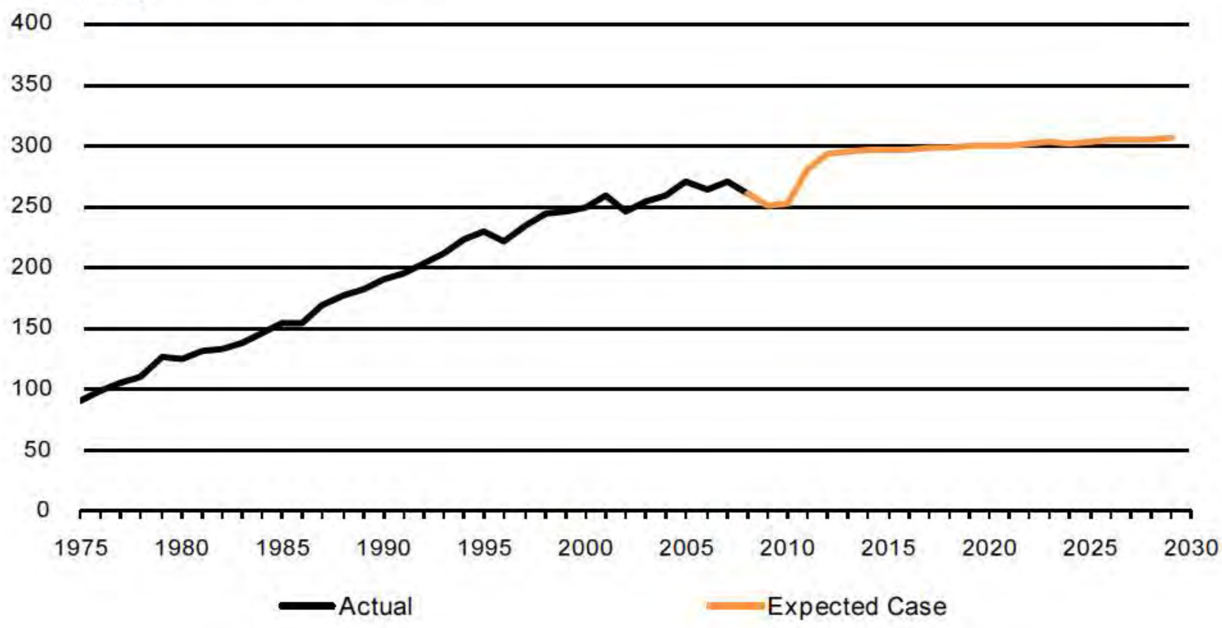
The industrial category is made up of Idaho Power's Large Power Service (Schedule 19) customers with metered demands exceeding 1,000 kilowatts (kw). In 1970, Idaho Power had about 50 industrial customers which represented 8 percent of Idaho Power system sales. By December 2008, the number of industrial customers had risen to 122, representing approximately 16 percent of system sales. Special contracts are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 251 aMW in 2009 to 306 aMW in 2029, an average annual growth rate of 1.0 percent (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.

Table 8. Industrial Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2028
Expected Case	251	297	300	306	1.0%

Figure 9. Forecasted Industrial Load
(aMW)

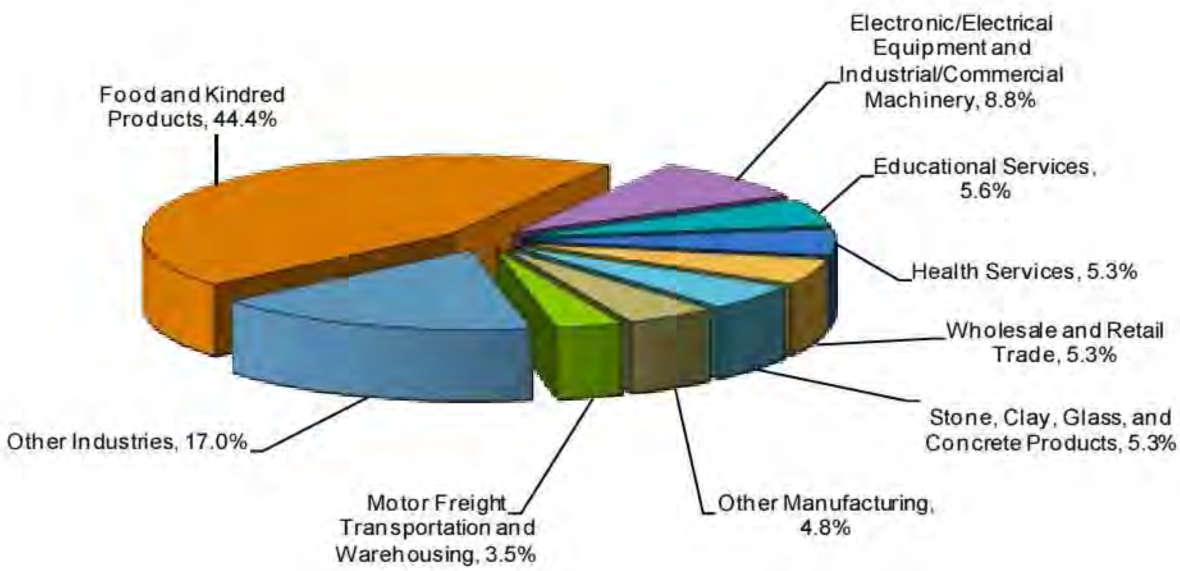


The industrial energy forecast is based on the most recent (June 2009) national, state, MSA, and county economic forecasts from Moody's Analytics and the resulting derived economic forecast for Idaho Power's service area.

Since rate tariff definitions do not correspond with economic activity types, Idaho Power's Schedule 19 customers were categorized, and their historical electricity sales were summarized by economic activity. This is also true for the large commercial loads, so Schedule 9 Primary and Transmission customers' energy sales were also included for forecasting purposes and later recombined with the commercial sector sales forecast. The appropriate employment series (or population time series) were matched to each economic sector or industry group. Regression models were developed for 17 industry groups to determine the relationship between historical electricity sales and historical employment or population and other relevant explanatory variables. The estimated coefficients from the industry group regression models were then applied to the appropriate employment or population drivers, which resulted in the escalation of electricity sales to the various industry groups over time.

Figure 10 illustrates the 2008 industrial electricity consumption by industry group. By far the largest share of electricity was consumed by the Food and Kindred Products sector (44 percent), followed by Electronic/Electrical Equipment and Industrial/Commercial Machinery (9 percent); Educational Services (6 percent); and Health Services, Wholesale and Retail Trade, and Stone, Clay, Glass, and Concrete Products (each representing 5 percent). As Figure 10 shows, several other industry groups make up the remaining share of the 2008 industrial electricity consumption.

Figure 10. Industrial Electricity Consumption by Industry Group
(based on 2008 figures)



ADDITIONAL FIRM LOAD

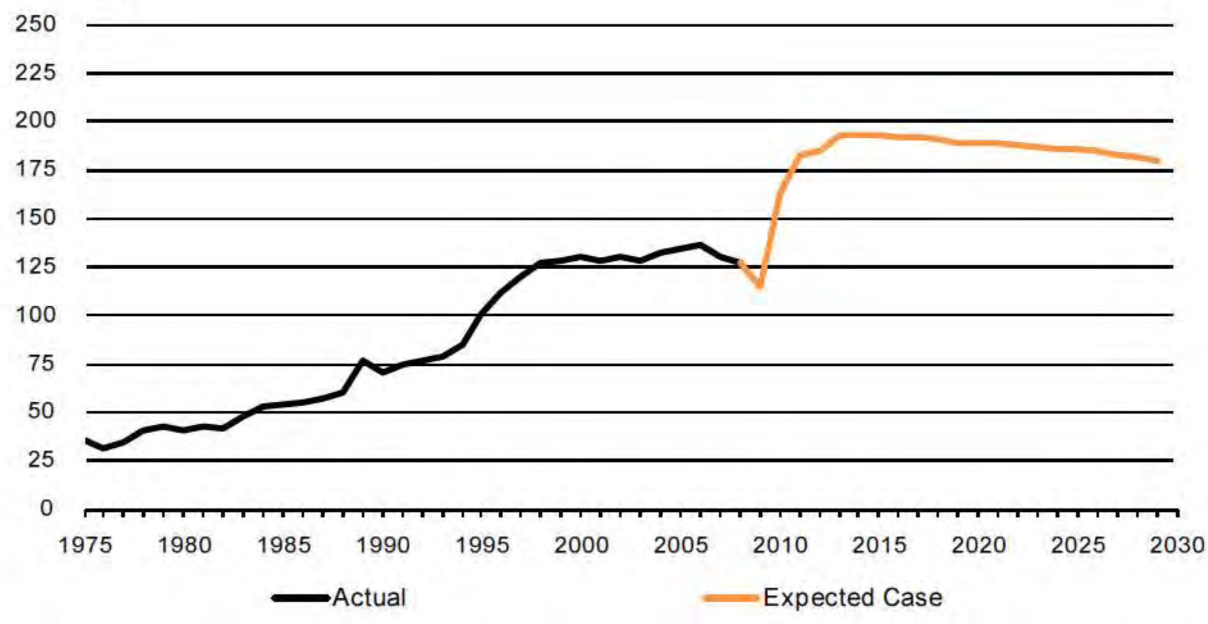
Special contracts currently exist for five large customers that are recognized as firm load customers. These customers are Micron Technology, Simplot Fertilizer, INL, Hoku Materials, and Raft River. Together, these customers make up the additional firm load category. Historically, a long-term firm sales contract existed with the City of Weiser. However, the contract with the City of Weiser expired as of December 31, 2006 and was not renewed.

In the expected-case forecast, additional firm load is expected to increase from 115 aMW in 2009 to 180 aMW in 2029, an average growth rate of 2.3 percent per year over the planning period (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.

Table 9. Additional Firm Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
Expected Case	115	193	189	180	2.3%

Figure 11. Forecasted Additional Firm Load
(aMW)



Micron Technology

Micron Technology is currently Idaho Power's largest individual customer and employs approximately 9,000 workers in the Boise area. In this forecast, electricity sales to Micron Technology are expected to move downward in 2009 as Micron phases out 200-millimeter (mm) dynamic random access memory (DRAM) operations at its Boise facility. The company will continue to operate its 300-mm research and development fabrication facility in Boise and perform a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, corporate, and general services. Once establishing a new floor for energy consumption at the facility at about a quarter less energy use than in recent years, Micron Technology's electricity use is expected to increase based on new product development and market demand reflected in Moody's Analytics forecast of manufacturing employment in the Electronic and Electrical sector for the Boise MSA.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States. The future electricity usage at the plant is expected to grow at a slow pace throughout the planning period (2010–2029). The primary driver of long-term electricity sales growth at Simplot Fertilizer is Moody's Analytics forecast of gross product in the Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing for the Pocatello MSA.

Idaho National Laboratory

The United States Department of Energy (DOE) provided an energy-consumption and peak-demand forecast through 2029 for the INL. The forecast calls for loads to increase through 2012, remain flat for six years, and then slowly decline throughout the remainder of the forecast period. Looking back well over a decade ago, the annual loads at the INL were quite volatile due to operational constraints affecting the availability of an on-site 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 increased considerably.

Hoku Materials

The sales and load forecast reflects the increased expected demand for energy and peak capacity of Idaho Power's newest special-contract customer, Hoku Materials, located in Pocatello, Idaho. Hoku Materials plans to begin operation in December 2009 and reach full capacity by October 2010. The current sales and load forecast assumes that Hoku Materials will consume 74 aMW of energy each year and have a peak demand of 82 MW (each measure excluding line losses), once continuous operation is reached in 2012.

Raft River Rural Electric Cooperative

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's former customers in Nevada. Idaho Power 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's load control area.

The contract with Raft River expired on September 30, 2009. However, Raft River may renew the agreement on a year-to-year basis for two additional one-year terms, which would extend service until September 30, 2011. The load forecasts in the 2009 IRP assume that Idaho Power will continue to provide service to the Raft River area by extending contracts each year through September 30, 2011.

Company Firm Load

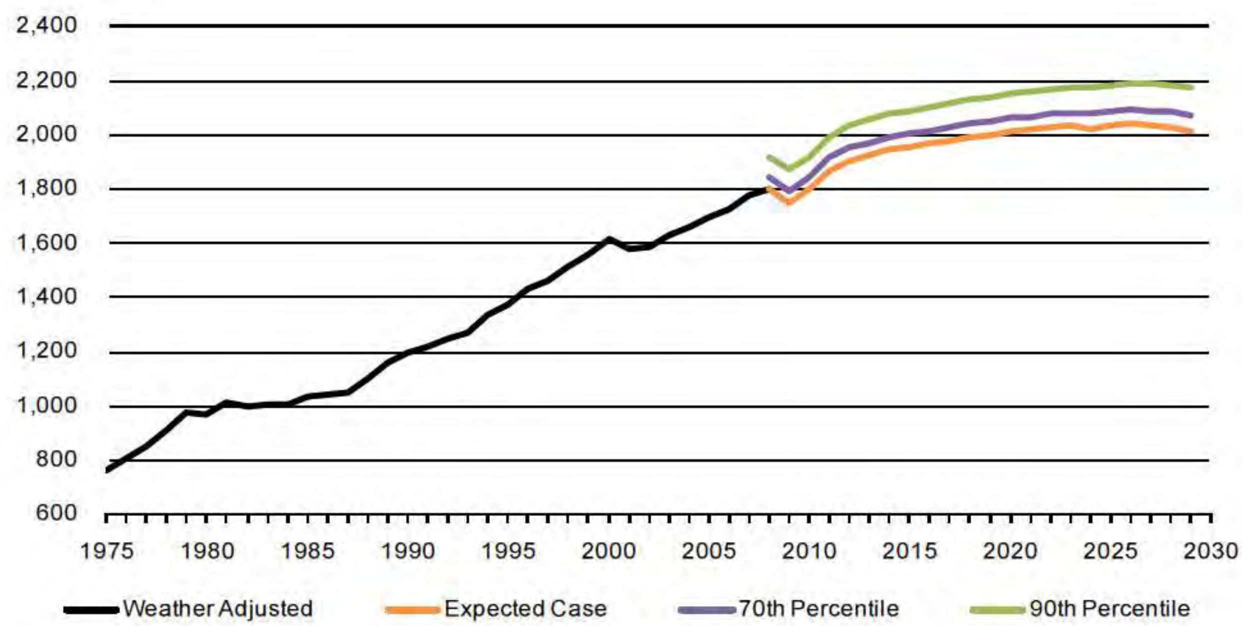
Firm load is the sum of the individual loads of the residential, commercial, industrial, and irrigation customers, as well as special contracts (excluding Astaris), past sales to the City of Weiser, and Raft River. Firm load excludes not only Astaris, but also all contracts to provide firm energy to 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.

In the expected-case forecast, total firm load is expected to increase from 1,752 aMW in 2009 to 2,015 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 10). In the 70th percentile forecast, total firm load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 10). The three scenarios of projected firm load are illustrated in Figure 12.

Table 10. Firm Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	1,875	2,078	2,141	2,172	0.7%
70th Percentile	1,796	1,994	2,051	2,070	0.7%
Expected Case	1,752	1,947	2,002	2,015	0.7%

Figure 12. Forecasted Firm Load
(aMW)



This page left blank intentionally.

Company Firm Peak

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

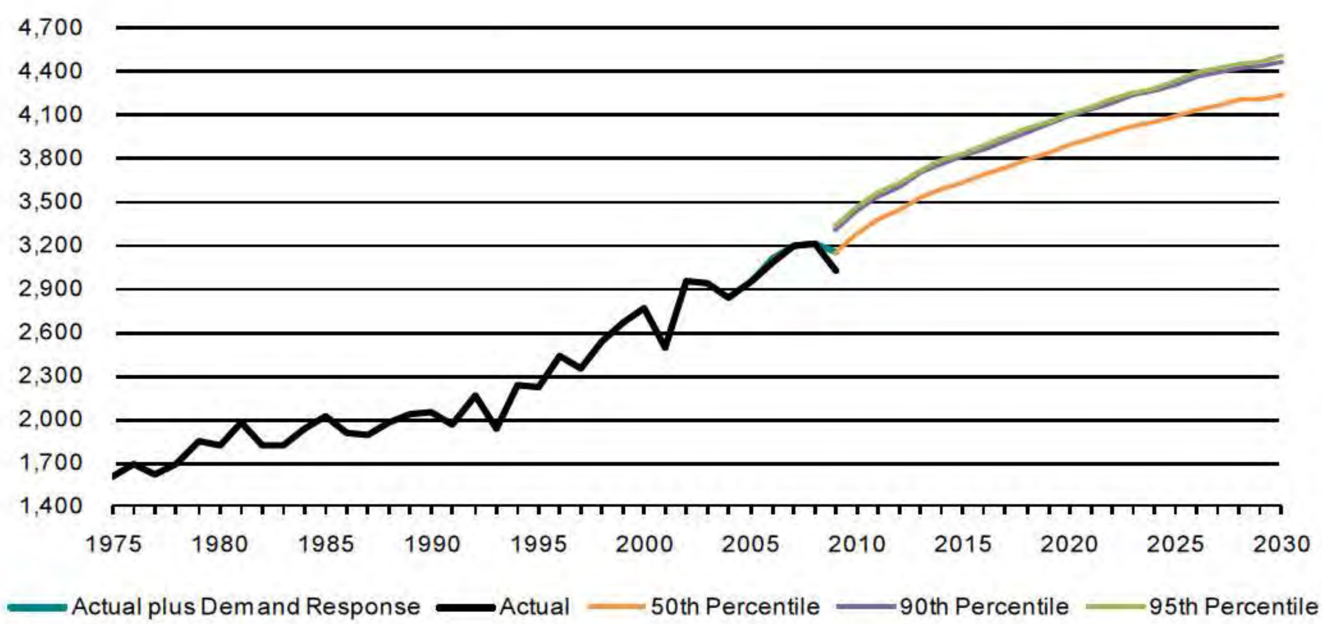
The all-time firm summer peak demand was 3,214 MW, recorded on Monday, June 30, 2008, at 3:00 p.m. The previous year's summer peak demand was 3,193 MW and occurred on Friday, July 13, 2007, at 4:00 p.m. The summer firm peak load growth has accelerated over the past ten years as air conditioning has become standard in nearly all new residential home construction and new commercial buildings. The 2001 summer peak was dampened by the nearly 30 percent curtailment 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 3,310 MW in 2009 to 4,445 MW in the year 2029, an average growth rate of 1.5 percent per year over the planning period (Table 11). In the 95th percentile forecast, total firm summer peak load is expected to increase from 3,330 MW in 2009 to 4,475 MW in the year 2029. The three scenarios of projected firm summer peak load are illustrated in Figure 13.

Table 11. Firm Summer Peak-Load Growth
(MW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
95th Percentile	3,330	3,789	4,060	4,475	1.5%
90th Percentile	3,310	3,766	4,034	4,445	1.5%
50th Percentile	3,154	3,592	3,842	4,216	1.5%

Figure 13. Forecasted Firm Summer Peak
(MW)



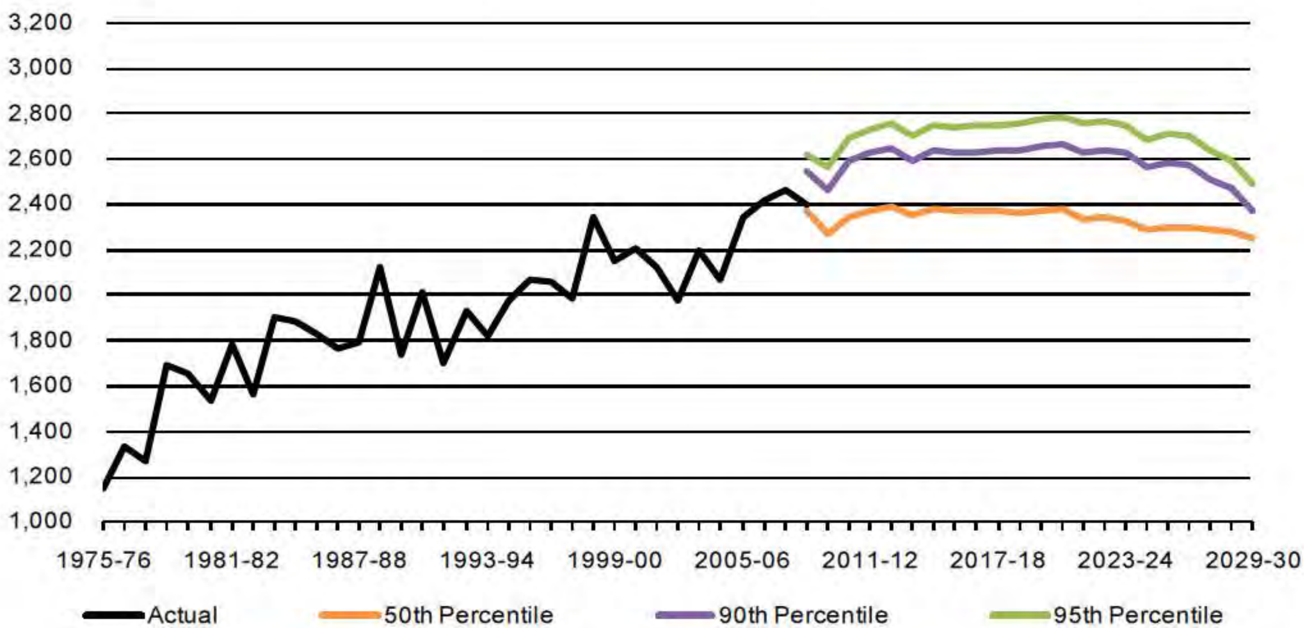
The maximum firm winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. As shown in Figure 14, historical firm winter peak load is much more variable than summer firm peak load. This is because the variability of peak day temperatures in winter months is far greater than the variability of 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 decrease from 2,466 MW in 2009 to 2,376 MW in 2029, an average growth rate of –0.2 percent per year over the planning period (Table 12). In the 95th percentile forecast, total firm winter peak load is expected to decrease from 2,565 MW in 2009 to 2,493 MW in 2029, an average growth rate of –0.1 percent per year over the planning period (Table 12). The three scenarios of projected firm winter peak load are illustrated in Figure 14.

Table 12. Firm Winter Peak Load Growth
(MW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
95th Percentile	2,565	2,748	2,773	2,493	-0.1%
90th Percentile	2,466	2,637	2,654	2,376	-0.2%
50th Percentile	2,270	2,385	2,370	2,250	0.0%

Figure 14. Forecasted Firm Winter Peak
(MW)



COMPANY SYSTEM LOAD

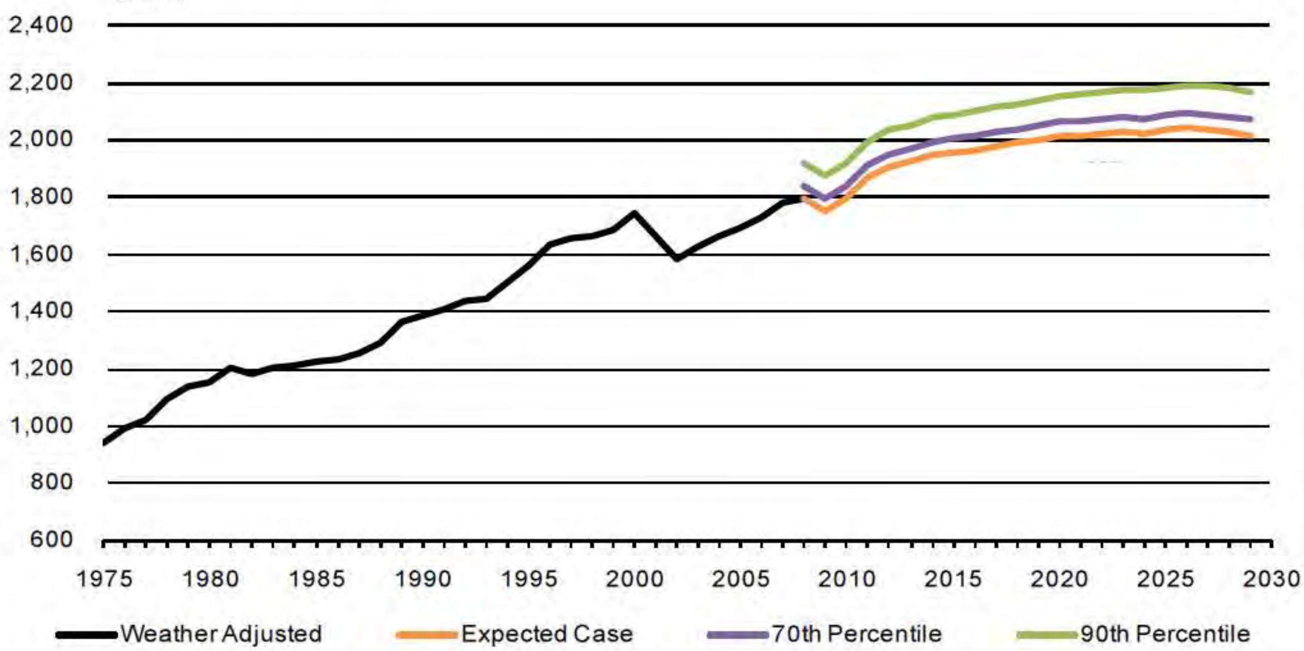
System load historically is made up of firm load plus Astaris load, but excludes long-term, off-system contracts. The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris was Idaho Power's largest individual customer and, in some past years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated. Since Astaris ceased production in April 2002, system load and firm load are identical.

The expected-case system load forecast is based on the most recent Moody's Analytics economic forecast for the nation and 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 0.7 percent per year over the 2009–2029 time period. Company system load projections are reported in Table 13 and shown in Figure 15.

Table 13. System Load Growth
(aMW)

Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	1,875	2,078	2,141	2,172	0.7%
70th Percentile	1,796	1,994	2,051	2,070	0.7%
Expected Case	1,752	1,947	2,002	2,015	0.7%

Figure 15. Forecasted System Load
(aMW)



In the expected-case forecast, company system load is expected to increase from 1,752 aMW in 2009 to 2,015 aMW in 2029. In the 70th percentile forecast, company system load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029, an average growth rate of 0.7 percent per year over the planning period (Table 13).

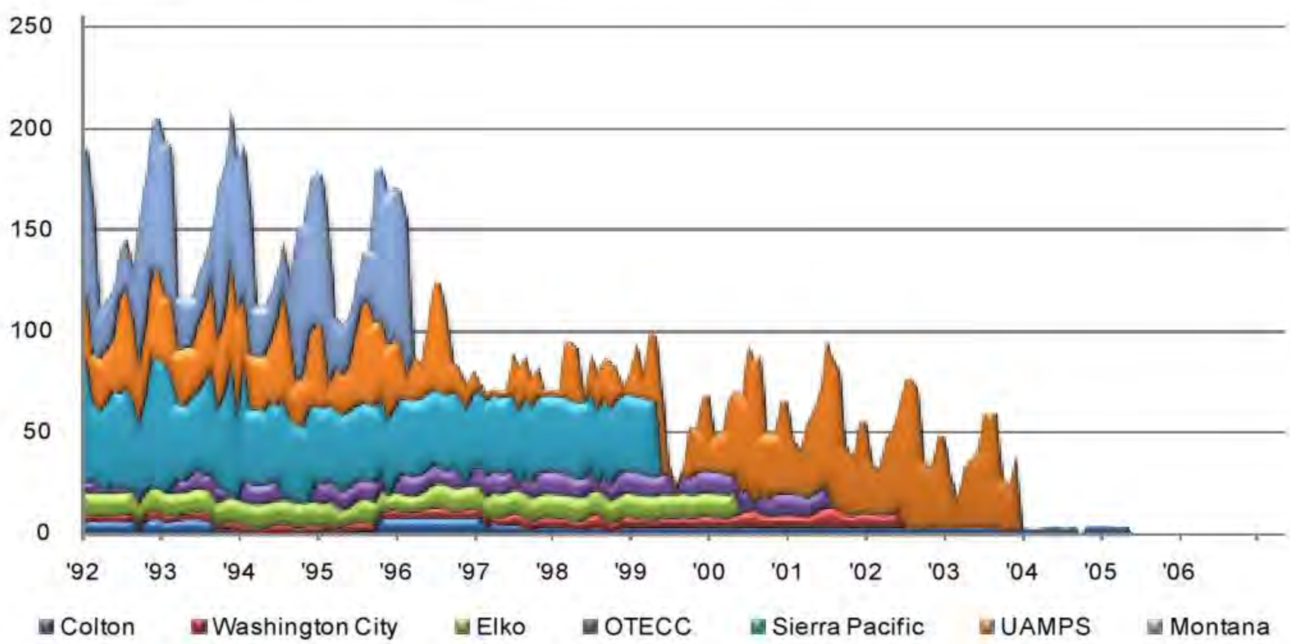
This page left blank intentionally.

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 effective during the forecast period lasting for more than one year. At this time, there are no long-term contracts.

As illustrated in Figure 16, 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 Idaho Power's surplus energy diminished due to retail load growth. In the future, Idaho Power may enter into additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

Figure 16. Forecasted Contract Off-System Load by Customer
(aMW)



This page left blank intentionally.

TOTAL COMPANY LOAD

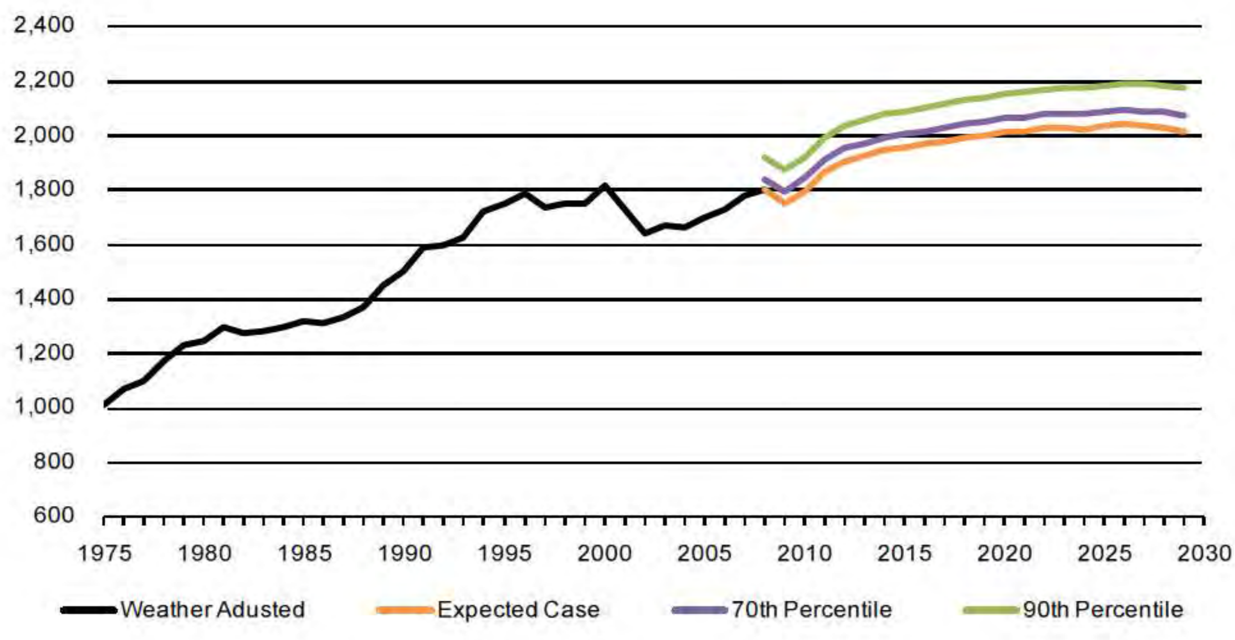
Accompanied by an outlook of moderate economic growth for Idaho Power's service area throughout the forecast period, *Appendix A–Sales and Load Forecast* projects continued growth in Idaho Power's total load. Total load is made up of system load plus long-term firm off-system contracts. At this time, there are no contracts in effect to provide long-term firm energy off-system.

Total company load projections are listed in Table 14 and illustrated in Figure 17. The expected-case scenario average growth rate of 0.7 percent per year represents the most probable outlook expected by Idaho Power. In the 70th percentile forecast, company total load is expected to increase from 1,796 aMW in 2009 to 2,070 aMW by 2029.

Table 14. Total Company Load Growth
(aMW)

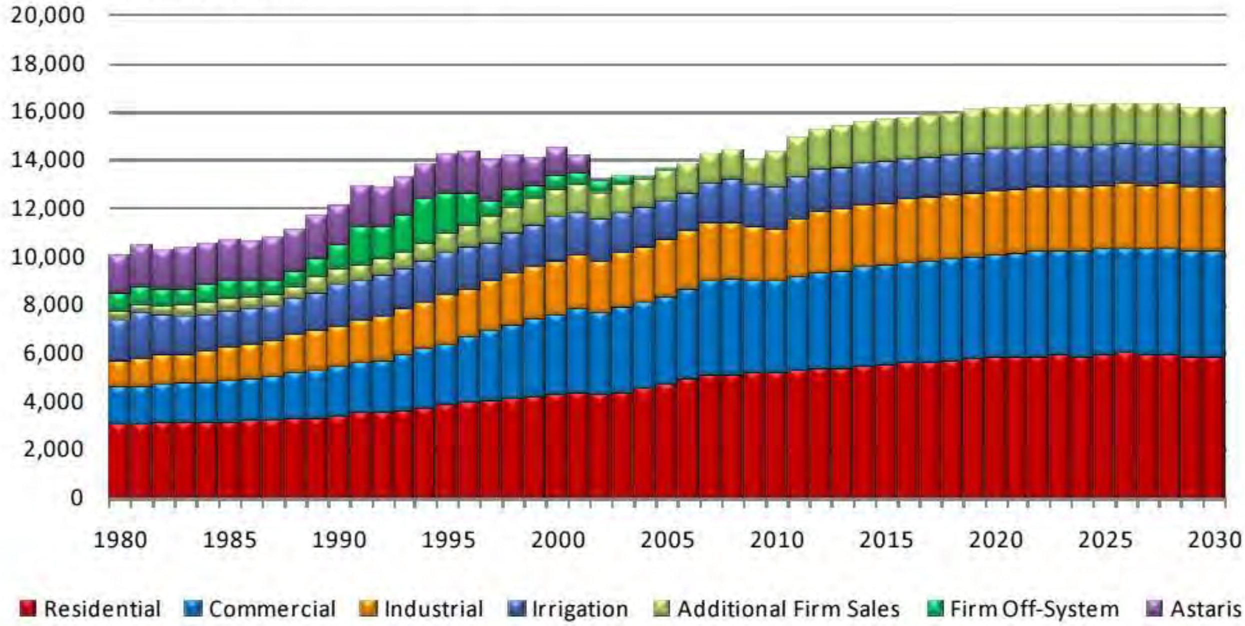
Growth	2009	2014	2019	2029	Growth Rate (per year) 2009–2029
90th Percentile	1,875	2,078	2,141	2,172	0.7%
70th Percentile	1,796	1,994	2,051	2,070	0.7%
Expected Case	1,752	1,947	2,002	2,015	0.7%

Figure 17. Forecasted Total Load
(aMW)



The composition of total company electricity sales by year is shown in Figure 18. Residential sales are forecast to be over 13 percent higher in 2029, gaining nearly 0.7 million MWh over 2009. Commercial sales are expected to be nearly 15 percent higher or nearly 0.6 million MWh above 2009 followed by industrial (22 percent higher or nearly 0.5 million additional MWh) and irrigation (nearly 10 percent lower than 2029). Electricity sales to Astaris ended in April 2002.

Figure 18. Composition of Electricity Sales
(thousands of MWh)



The additional firm sales category (which represents sales to Micron Technology, Simplot Fertilizer, INL, Hoku Materials, and Raft River) is forecast to grow by nearly 57 percent over the 2009–2029 time period, largely due to the addition of Hoku Materials as a special contract customer.

DEMAND-SIDE MANAGEMENT

DSM consists of energy efficiency programs which reduce customer energy use year-round and demand response programs that are targeted at reducing load during specific periods of high demand. The impact of energy efficiency programs are integrated into *Appendix A –Sales and Load Forecast;* however, demand response programs are accounted for in the 2009 IRP load and resource balance. The sales and load forecast, adjusted for existing and committed energy efficiency programs, serves as the basis for establishing the baseline forecast for surpluses and deficits which are used to develop portfolios for the IRP. Table 15 shows the existing and committed energy efficiency programs included in the current sales and load forecast.

Table 15. DSM Programs

DSM Program	Customer Sector
Building Efficiency	Commercial/Industrial
Custom Efficiency	Commercial/Industrial
Easy Upgrades	Commercial/Industrial
Energy House Calls	Residential
Home Products Program	Residential
ENERGY STAR® Homes Northwest	Residential
Energy Efficient Lighting	Residential
Heating & Cooling Efficiency Program	Residential
Irrigation Efficiency Rewards	Irrigation
Oregon Residential Weatherization	Residential
Rebate Advantage	Residential
Weatherization Assistance for Qualified Customers (WAQC)	Residential

Energy Efficiency Programs

In developing data for the forecasting regression models, historical energy sales are adjusted for program performance in past years (which is added to the sales history) in order to isolate sales relationships to the causative independent drivers (economic, demographic, weather, price, et al.) from the impact of energy efficiency programs. The forecast resulting from the adjusted history is designed to reflect sales without the impact of energy efficiency programs. The results from the regression models are subsequently adjusted downward to account for future energy efficiency program performance.

The reduced energy use for each customer class associated with each of the existing energy efficiency programs is shown in Appendix A2. Energy savings from energy efficiency programs are typically measured and reported at the point of delivery (customers' meter). Therefore, energy efficiency savings are increased by the amount of energy lost in transmitting the electricity from the generation source to the customers' meter.

Because the sales and load forecast is prepared before new energy efficiency programs are determined, new energy efficiency programs are not included in the sales and load forecast. The impact of the new programs is accounted for in the IRP load and resource balance prior to determining the need for additional supply-side resources. The forecast performance of both existing and new energy efficiency and demand response programs are shown in the load and resource balance in *Appendix C–Technical Appendix*. In the next planning cycle, the impact of new committed programs will be accounted for in the updated sales and load forecast.

Demand Response Programs

Prior to the 2009 IRP, demand response program performance was accounted for in the sales and load forecast. Beginning with the 2009 IRP, demand response programs are accounted for in the load and resource balance. Demand response programs are described in greater detail in Chapter 4 of the 2009 IRP and in *Appendix C-Technical Appendix*.

Demand response programs are treated as supply-side resources in the IRP and are not incorporated into the sales and load forecast. In the load and resource balance, the forecast performance of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply-side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. Because energy efficiency programs tend to result in reduced load year-round, there is a component of peak-hour load reduction due to energy efficiency programs that is integrated into the sales and load forecast. This provides a consistent treatment of both types of programs as all energy efficiency programs are integrated into the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B–Demand-Side Management 2008 Annual Report*.

Appendix A1. Historical and Projected Sales and Load

Residential Load

Historical Residential Sales and Load, 1970–2008
(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	132,135		9,983	1,319		152
1971	138,071	4.5%	10,539	1,455	10.3%	167
1972	145,208	5.2%	10,955	1,591	9.3%	184
1973	152,957	5.3%	11,525	1,763	10.8%	202
1974	160,151	4.7%	12,057	1,931	9.5%	223
1975	167,622	4.7%	12,939	2,169	12.3%	250
1976	175,720	4.8%	13,445	2,363	8.9%	271
1977	184,561	5.0%	13,673	2,524	6.8%	290
1978	194,650	5.5%	14,256	2,775	10.0%	321
1979	202,982	4.3%	14,766	2,997	8.0%	342
1980	209,629	3.3%	14,580	3,056	2.0%	348
1981	213,579	1.9%	14,346	3,064	0.2%	349
1982	216,696	1.5%	14,393	3,119	1.8%	356
1983	219,849	1.5%	14,334	3,151	1.0%	362
1984	222,695	1.3%	14,145	3,150	0.0%	357
1985	225,185	1.1%	14,055	3,165	0.5%	362
1986	227,081	0.8%	14,168	3,217	1.7%	367
1987	228,868	0.8%	14,068	3,220	0.1%	366
1988	230,771	0.8%	14,326	3,306	2.7%	377
1989	233,370	1.1%	14,342	3,347	1.2%	384
1990	238,117	2.0%	14,300	3,405	1.7%	393
1991	243,207	2.1%	14,488	3,524	3.5%	401
1992	249,767	2.7%	14,135	3,531	0.2%	407
1993	258,271	3.4%	14,173	3,660	3.7%	413
1994	267,854	3.7%	14,001	3,750	2.4%	434
1995	277,131	3.5%	13,973	3,872	3.3%	437
1996	286,227	3.3%	13,743	3,934	1.6%	456
1997	294,674	3.0%	13,681	4,031	2.5%	463
1998	303,300	2.9%	13,713	4,159	3.2%	475
1999	312,901	3.2%	13,583	4,250	2.2%	487
2000	322,402	3.0%	13,383	4,315	1.5%	499
2001	331,009	2.7%	13,163	4,357	1.0%	476
2002	339,764	2.6%	12,620	4,288	–1.6%	488
2003	349,219	2.8%	12,645	4,416	3.0%	507
2004	360,462	3.2%	12,689	4,574	3.6%	525
2005	373,602	3.6%	12,650	4,726	3.3%	541
2006	387,707	3.8%	12,842	4,979	5.3%	566
2007	397,286	2.5%	12,885	5,119	2.8%	583
2008	402,520	1.3%	12,823	5,161	0.8%	590

Residential Load

Projected Residential Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	404,916	0.6%	12,779	5,174	0.3%	590
2010	406,743	0.5%	12,707	5,168	–0.1%	591
2011	409,192	0.6%	12,846	5,256	1.7%	601
2012	414,346	1.3%	12,984	5,380	2.3%	614
2013	422,101	1.9%	12,737	5,376	–0.1%	615
2014	430,667	2.0%	12,746	5,489	2.1%	627
2015	439,230	2.0%	12,592	5,531	0.8%	632
2016	447,681	1.9%	12,480	5,587	1.0%	638
2017	456,082	1.9%	12,379	5,646	1.0%	645
2018	464,527	1.9%	12,274	5,701	1.0%	651
2019	473,045	1.8%	12,197	5,770	1.2%	659
2020	481,587	1.8%	12,129	5,841	1.2%	667
2021	490,126	1.8%	11,918	5,841	0.0%	667
2022	498,618	1.7%	11,824	5,895	0.9%	673
2023	507,071	1.7%	11,714	5,940	0.8%	678
2024	515,508	1.7%	11,427	5,891	–0.8%	673
2025	523,994	1.6%	11,365	5,955	1.1%	680
2026	532,612	1.6%	11,260	5,997	0.7%	684
2027	541,310	1.6%	11,006	5,957	–0.7%	680
2028	550,147	1.6%	10,830	5,958	0.0%	680
2029	559,091	1.6%	10,494	5,867	–1.5%	670

Commercial Load

Historical Commercial Sales and Load, 1970–2008

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	21,375		42,768	914		105
1971	22,077	3.3%	45,386	1,002	9.6%	115
1972	22,585	2.3%	46,141	1,042	4.0%	120
1973	23,286	3.1%	48,142	1,121	7.6%	128
1974	24,096	3.5%	49,025	1,181	5.4%	136
1975	25,045	3.9%	51,217	1,283	8.6%	147
1976	26,034	3.9%	52,509	1,367	6.6%	157
1977	27,112	4.1%	52,415	1,421	4.0%	162
1978	27,831	2.7%	52,467	1,460	2.8%	169
1979	28,087	0.9%	56,394	1,584	8.5%	180
1980	28,797	2.5%	54,135	1,559	-1.6%	178
1981	29,567	2.7%	54,278	1,605	2.9%	184
1982	30,167	2.0%	54,126	1,633	1.7%	186
1983	30,776	2.0%	52,649	1,620	-0.8%	186
1984	31,554	2.5%	53,312	1,682	3.8%	191
1985	32,417	2.7%	53,944	1,749	4.0%	200
1986	33,208	2.4%	53,590	1,780	1.8%	203
1987	33,975	2.3%	53,126	1,805	1.4%	205
1988	34,723	2.2%	54,319	1,886	4.5%	215
1989	35,638	2.6%	55,327	1,972	4.5%	226
1990	36,785	3.2%	55,922	2,057	4.3%	236
1991	37,922	3.1%	56,027	2,125	3.3%	243
1992	39,022	2.9%	56,292	2,197	3.4%	253
1993	40,047	2.6%	57,764	2,313	5.3%	262
1994	41,629	4.0%	58,187	2,422	4.7%	280
1995	43,165	3.7%	58,523	2,526	4.3%	287
1996	44,995	4.2%	61,940	2,787	10.3%	322
1997	46,819	4.1%	62,007	2,903	4.2%	333
1998	48,404	3.4%	62,771	3,038	4.7%	348
1999	49,430	2.1%	64,085	3,168	4.3%	363
2000	50,117	1.4%	66,079	3,312	4.5%	383
2001	51,501	2.8%	67,424	3,472	4.9%	383
2002	52,915	2.7%	64,650	3,421	-1.5%	389
2003	54,194	2.4%	64,268	3,483	1.8%	399
2004	55,577	2.6%	63,972	3,555	2.1%	407
2005	57,145	2.8%	63,472	3,627	2.0%	414
2006	59,050	3.3%	63,320	3,739	3.1%	425
2007	61,640	4.4%	63,233	3,898	4.2%	444
2008	63,492	3.0%	62,122	3,944	1.2%	449

Commercial Load

Projected Commercial Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	64,261	1.2%	59,445	3,820	–3.2%	437
2010	64,925	1.0%	58,988	3,830	0.3%	438
2011	65,712	1.2%	59,205	3,890	1.6%	445
2012	67,085	2.1%	59,330	3,980	2.3%	455
2013	68,768	2.5%	58,863	4,048	1.7%	463
2014	70,486	2.5%	58,172	4,100	1.3%	469
2015	72,191	2.4%	57,262	4,134	0.8%	472
2016	73,883	2.3%	56,354	4,164	0.7%	476
2017	75,568	2.3%	55,480	4,193	0.7%	479
2018	77,249	2.2%	54,646	4,221	0.7%	482
2019	78,930	2.2%	53,842	4,250	0.7%	486
2020	80,608	2.1%	53,054	4,277	0.6%	489
2021	82,282	2.1%	52,180	4,293	0.4%	490
2022	83,952	2.0%	51,378	4,313	0.5%	493
2023	85,621	2.0%	50,569	4,330	0.4%	495
2024	87,288	1.9%	49,653	4,334	0.1%	495
2025	88,956	1.9%	48,907	4,351	0.4%	497
2026	90,628	1.9%	48,165	4,365	0.3%	499
2027	92,301	1.8%	47,350	4,370	0.1%	499
2028	93,980	1.8%	46,599	4,379	0.2%	500
2029	95,661	1.8%	45,780	4,379	0.0%	500

Irrigation Load

Historical Irrigation Sales and Load, 1970–2008

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	7,319		117,492	860		98
1971	7,518	2.7%	132,445	996	15.8%	114
1972	7,815	4.0%	126,555	989	-0.7%	113
1973	8,341	6.7%	134,540	1,122	13.5%	128
1974	8,971	7.6%	143,892	1,291	15.0%	147
1975	9,480	5.7%	153,349	1,454	12.6%	166
1976	9,936	4.8%	153,080	1,521	4.6%	173
1977	10,238	3.0%	156,073	1,598	5.1%	182
1978	10,476	2.3%	152,167	1,594	-0.2%	183
1979	10,711	2.2%	158,121	1,694	6.2%	193
1980	10,854	1.3%	154,113	1,673	-1.2%	190
1981	11,248	3.6%	163,787	1,842	10.1%	210
1982	11,312	0.6%	148,385	1,679	-8.9%	192
1983	11,133	-1.6%	143,103	1,593	-5.1%	182
1984	11,375	2.2%	130,822	1,488	-6.6%	169
1985	11,576	1.8%	129,069	1,494	0.4%	171
1986	11,308	-2.3%	132,200	1,495	0.1%	171
1987	11,254	-0.5%	124,128	1,397	-6.6%	160
1988	11,378	1.1%	131,448	1,496	7.1%	170
1989	11,957	5.1%	136,351	1,630	9.0%	186
1990	12,340	3.2%	141,532	1,747	7.1%	199
1991	12,484	1.2%	134,476	1,679	-3.9%	192
1992	12,809	2.6%	134,469	1,722	2.6%	196
1993	13,078	2.1%	128,681	1,683	-2.3%	192
1994	13,559	3.7%	125,547	1,702	1.2%	194
1995	13,679	0.9%	126,417	1,729	1.6%	197
1996	14,074	2.9%	122,219	1,720	-0.5%	196
1997	14,383	2.2%	111,783	1,608	-6.5%	184
1998	14,695	2.2%	112,347	1,651	2.7%	188
1999	14,912	1.5%	115,126	1,717	4.0%	196
2000	15,253	2.3%	121,883	1,859	8.3%	212
2001	15,522	1.8%	110,306	1,712	-7.9%	195
2002	15,840	2.0%	105,996	1,679	-1.9%	192
2003	16,020	1.1%	106,160	1,701	1.3%	194
2004	16,297	1.7%	103,886	1,693	-0.4%	193
2005	16,936	3.9%	97,135	1,645	-2.8%	188
2006	17,062	0.7%	94,015	1,604	-2.5%	183
2007	17,001	-0.4%	100,043	1,701	6.0%	194
2008	17,428	2.5%	105,738	1,843	8.3%	210

Irrigation Load

Projected Irrigation Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	17,705	1.6%	100,269	1,775	–3.7%	203
2010	17,982	1.6%	94,477	1,699	–4.3%	194
2011	18,261	1.6%	93,557	1,708	0.6%	195
2012	18,537	1.5%	91,454	1,695	–0.8%	193
2013	18,812	1.5%	89,510	1,684	–0.7%	192
2014	19,090	1.5%	87,891	1,678	–0.4%	192
2015	19,367	1.5%	86,947	1,684	0.4%	192
2016	19,644	1.4%	85,637	1,682	–0.1%	192
2017	19,921	1.4%	84,516	1,684	0.1%	192
2018	20,199	1.4%	83,465	1,686	0.1%	192
2019	20,474	1.4%	82,524	1,690	0.2%	193
2020	20,755	1.4%	81,683	1,695	0.3%	193
2021	21,031	1.3%	80,425	1,691	–0.2%	193
2022	21,308	1.3%	79,093	1,685	–0.4%	192
2023	21,583	1.3%	78,135	1,686	0.1%	193
2024	21,861	1.3%	76,541	1,673	–0.8%	190
2025	22,140	1.3%	75,146	1,664	–0.6%	190
2026	22,415	1.2%	74,420	1,668	0.3%	190
2027	22,691	1.2%	73,007	1,657	–0.7%	189
2028	22,967	1.2%	71,354	1,639	–1.1%	187
2029	23,244	1.2%	69,359	1,612	–1.6%	184

Industrial Load

Historical Industrial Sales and Load, 1970–2008

(weather-adjusted)

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	49		9,173,784	445		52
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%	91
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%	138
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%	177
1989	132	-0.6%	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
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%	260
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%	270
2006	127	1.0%	18,255,385	2,325	-1.1%	265
2007	123	-3.6%	19,275,551	2,366	1.8%	270
2008	119	-3.1%	19,415,391	2,308	-2.4%	261

Industrial Load

Projected Industrial Sales and Load, 2009–2029

Year	Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	123	3.2%	17,962,012	2,203	–4.6%	251
2010	123	0.3%	17,854,906	2,196	–0.3%	252
2011	125	1.6%	19,535,073	2,442	11.2%	281
2012	128	2.4%	20,058,798	2,568	5.1%	293
2013	128	0.0%	20,226,984	2,589	0.8%	296
2014	130	1.6%	19,997,345	2,600	0.4%	297
2015	131	0.8%	19,881,653	2,604	0.2%	297
2016	134	2.3%	19,485,326	2,611	0.3%	297
2017	134	0.0%	19,527,376	2,617	0.2%	299
2018	136	1.5%	19,281,769	2,622	0.2%	299
2019	136	0.0%	19,327,437	2,629	0.2%	300
2020	138	1.5%	19,089,792	2,634	0.2%	300
2021	140	1.4%	18,842,449	2,638	0.1%	301
2022	141	0.7%	18,758,363	2,645	0.3%	302
2023	141	0.0%	18,812,300	2,653	0.3%	303
2024	145	2.8%	18,316,503	2,656	0.1%	302
2025	146	0.7%	18,230,053	2,662	0.2%	304
2026	147	0.7%	18,153,540	2,669	0.3%	305
2027	148	0.7%	18,053,489	2,672	0.1%	305
2028	150	1.4%	17,857,001	2,679	0.2%	305
2029	151	0.7%	17,741,963	2,679	0.0%	306

Additional Firm Sales and Load*

Historical Additional Firm Sales and Load, 1970–2008

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	319		36
1971	295	-7.5%	34
1972	284	-3.7%	32
1973	290	2.2%	33
1974	282	-2.7%	32
1975	314	11.1%	36
1976	277	-11.9%	31
1977	311	12.4%	35
1978	357	14.8%	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	9.8%	53
1985	473	1.3%	54
1986	482	2.0%	55
1987	503	4.3%	57
1988	531	5.6%	60
1989	671	26.5%	77
1990	626	-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%	112
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
2006	1,189	1.2%	136
2007	1,142	-4.0%	130
2008	1,114	-2.4%	127

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

Additional Firm Sales and Load*

Projected Additional Firm Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	1,004	–9.9%	115
2010	1,429	42.3%	163
2011	1,605	12.3%	183
2012	1,621	1.0%	185
2013	1,687	4.1%	193
2014	1,690	0.2%	193
2015	1,689	0.0%	193
2016	1,684	–0.3%	192
2017	1,678	–0.3%	192
2018	1,676	–0.1%	191
2019	1,657	–1.1%	189
2020	1,657	0.0%	189
2021	1,652	–0.3%	189
2022	1,650	–0.1%	188
2023	1,637	–0.8%	187
2024	1,638	0.1%	186
2025	1,633	–0.3%	186
2026	1,619	–0.8%	185
2027	1,606	–0.9%	183
2028	1,595	–0.6%	182
2029	1,579	–1.0%	180

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

Company Firm Load

Historical Company Firm Load, 1970–2008
(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	3,857		487
1971	4,272	10.8%	539
1972	4,521	5.8%	571
1973	4,983	10.2%	628
1974	5,425	8.9%	685
1975	6,004	10.7%	759
1976	6,385	6.3%	805
1977	6,782	6.2%	854
1978	7,158	5.5%	907
1979	7,735	8.1%	972
1980	7,753	0.2%	971
1981	8,035	3.6%	1,011
1982	7,960	-0.9%	1,000
1983	7,983	0.3%	1,008
1984	8,069	1.1%	1,008
1985	8,238	2.1%	1,036
1986	8,330	1.1%	1,045
1987	8,398	0.8%	1,051
1988	8,764	4.4%	1,098
1989	9,215	5.1%	1,159
1990	9,496	3.1%	1,198
1991	9,707	2.2%	1,215
1992	9,900	2.0%	1,247
1993	10,200	3.0%	1,271
1994	10,564	3.6%	1,335
1995	11,026	4.4%	1,373
1996	11,363	3.1%	1,434
1997	11,632	2.4%	1,464
1998	12,106	4.1%	1,516
1999	12,416	2.6%	1,558
2000	12,820	3.3%	1,618
2001	12,948	1.0%	1,582
2002	12,683	-2.0%	1,586
2003	12,954	2.1%	1,627
2004	13,247	2.3%	1,663
2005	13,525	2.1%	1,697
2006	13,835	2.3%	1,729
2007	14,225	2.8%	1,780
2008	14,370	1.0%	1,798

Company Firm Load

Projected Company Firm Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	13,977	–2.7%	1,752
2010	14,322	2.5%	1,797
2011	14,902	4.0%	1,869
2012	15,244	2.3%	1,906
2013	15,384	0.9%	1,926
2014	15,557	1.1%	1,947
2015	15,642	0.5%	1,957
2016	15,728	0.5%	1,967
2017	15,817	0.6%	1,979
2018	15,907	0.6%	1,991
2019	15,995	0.6%	2,002
2020	16,105	0.7%	2,013
2021	16,116	0.1%	2,017
2022	16,189	0.5%	2,026
2023	16,245	0.3%	2,032
2024	16,192	–0.3%	2,024
2025	16,264	0.4%	2,035
2026	16,318	0.3%	2,041
2027	16,262	–0.3%	2,034
2028	16,250	–0.1%	2,030
2029	16,116	–0.8%	2,015

Astaris Load

Historical Astaris Sales and Load, 1970–2008

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
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
2006	0	0.0%	0
2007	0	0.0%	0
2008	0	0.0%	0

Astaris Load			
Projected Astaris Sales and Load, 2009–2029			
Year	**Billed Sales (thousands of MWh)**	**Percent Change**	**Average Load (MW)**
2009–2029	0	0.0%	0

Company System Load

Historical Company System Sales and Load, 1970–2008

(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,515		686
1971	5,781	4.8%	719
1972	6,340	9.7%	789
1973	6,628	4.5%	825
1974	7,068	6.6%	882
1975	7,561	7.0%	945
1976	7,960	5.3%	994
1977	8,200	3.0%	1,024
1978	8,701	6.1%	1,092
1979	9,130	4.9%	1,139
1980	9,266	1.5%	1,152
1981	9,669	4.3%	1,207
1982	9,514	-1.6%	1,186
1983	9,593	0.8%	1,201
1984	9,770	1.9%	1,212
1985	9,851	0.8%	1,229
1986	9,884	0.3%	1,231
1987	10,090	2.1%	1,254
1988	10,400	3.1%	1,293
1989	10,918	5.0%	1,363
1990	11,101	1.7%	1,390
1991	11,316	1.9%	1,408
1992	11,470	1.4%	1,435
1993	11,637	1.5%	1,444
1994	11,984	3.0%	1,505
1995	12,593	5.1%	1,561
1996	13,051	3.6%	1,636
1997	13,260	1.6%	1,659
1998	13,378	0.9%	1,668
1999	13,467	0.7%	1,684
2000	13,874	3.0%	1,744
2001	13,607	-1.9%	1,661
2002	12,695	-6.7%	1,587
2003	12,954	2.0%	1,627
2004	13,247	2.3%	1,663
2005	13,525	2.1%	1,697
2006	13,835	2.3%	1,729
2007	14,225	2.8%	1,780
2008	14,370	1.0%	1,798

Company System Load

Projected Company System Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	13,977	–2.7%	1,752
2010	14,322	2.5%	1,797
2011	14,902	4.0%	1,869
2012	15,244	2.3%	1,906
2013	15,384	0.9%	1,926
2014	15,557	1.1%	1,947
2015	15,642	0.5%	1,957
2016	15,728	0.5%	1,967
2017	15,817	0.6%	1,979
2018	15,907	0.6%	1,991
2019	15,995	0.6%	2,002
2020	16,105	0.7%	2,013
2021	16,116	0.1%	2,017
2022	16,189	0.5%	2,026
2023	16,245	0.3%	2,032
2024	16,192	–0.3%	2,024
2025	16,264	0.4%	2,035
2026	16,318	0.3%	2,041
2027	16,262	–0.3%	2,034
2028	16,250	–0.1%	2,030
2029	16,116	–0.8%	2,015

Contract Off-System Load

Historical Contract Off-System Sales and Load, 1970–2008

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
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
2006	0	-100.0%	0
2007	0	0.0%	0
2008	0	0.0%	0

Contract Off-System Load			
Projected Contract Off-System Sales and Load, 2009–2029			
Year	**Billed Sales (thousands of MWh)**	**Percent Change**	**Average Load (MW)**
2009–2029	0	0.0%	0

Total Company Load

Historical Total Company Sales and Load, 1970–2008
(weather-adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
1970	5,901		732
1971	6,220	5.4%	771
1972	6,788	9.1%	841
1973	7,118	4.9%	883
1974	7,569	6.3%	941
1975	8,129	7.4%	1,012
1976	8,573	5.5%	1,066
1977	8,859	3.3%	1,101
1978	9,384	5.9%	1,173
1979	9,889	5.4%	1,229
1980	10,028	1.4%	1,242
1981	10,422	3.9%	1,296
1982	10,250	-1.6%	1,273
1983	10,303	0.5%	1,285
1984	10,517	2.1%	1,300
1985	10,630	1.1%	1,321
1986	10,554	-0.7%	1,310
1987	10,734	1.7%	1,330
1988	11,075	3.2%	1,373
1989	11,658	5.3%	1,451
1990	12,069	3.5%	1,504
1991	12,853	6.5%	1,590
1992	12,818	-0.3%	1,594
1993	13,194	2.9%	1,628
1994	13,795	4.6%	1,719
1995	14,176	2.8%	1,748
1996	14,336	1.1%	1,787
1997	13,934	-2.8%	1,738
1998	14,094	1.1%	1,753
1999	14,035	-0.4%	1,752
2000	14,461	3.0%	1,813
2001	14,145	-2.2%	1,725
2002	13,148	-7.0%	1,641
2003	13,300	1.2%	1,668
2004	13,267	-0.3%	1,665
2005	13,535	2.0%	1,698
2006	13,835	2.2%	1,729
2007	14,225	2.8%	1,780
2008	14,370	1.0%	1,798

Total Company Load

Projected Total Company Sales and Load, 2009–2029

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (MW)
2009	13,977	–2.7%	1,752
2010	14,322	2.5%	1,797
2011	14,902	4.0%	1,869
2012	15,244	2.3%	1,906
2013	15,384	0.9%	1,926
2014	15,557	1.1%	1,947
2015	15,642	0.5%	1,957
2016	15,728	0.5%	1,967
2017	15,817	0.6%	1,979
2018	15,907	0.6%	1,991
2019	15,995	0.6%	2,002
2020	16,105	0.7%	2,013
2021	16,116	0.1%	2,017
2022	16,189	0.5%	2,026
2023	16,245	0.3%	2,032
2024	16,192	–0.3%	2,024
2025	16,264	0.4%	2,035
2026	16,318	0.3%	2,041
2027	16,262	–0.3%	2,034
2028	16,250	–0.1%	2,030
2029	16,116	–0.8%	2,015

Appendix A2. Demand-Side Management Program Impacts

Energy Efficiency Programs

Residential Programs
(MWh including losses)

	Energy Reductions												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	2,058	1,871	2,075	2,007	2,049	1,852	1,913	1,913	1,999	2,067	1,999	2,067	23,871
2011	3,410	3,100	3,437	3,325	3,397	3,104	3,199	3,208	3,311	3,424	3,311	3,437	39,663
2012	4,544	4,114	4,563	4,394	4,525	4,146	4,281	4,289	4,375	4,563	4,394	4,525	52,712
2013	5,662	5,125	5,662	5,498	5,662	5,188	5,370	5,370	5,453	5,684	5,475	5,639	65,786
2014	6,781	6,138	6,781	6,584	6,781	6,244	6,454	6,446	6,558	6,807	6,532	6,781	78,886
2015	7,711	6,980	7,711	7,487	7,682	7,131	7,370	7,360	7,487	7,740	7,428	7,711	89,798
2016	8,613	7,828	8,682	8,397	8,578	8,023	8,268	8,293	8,363	8,647	8,363	8,682	100,736
2017	9,587	8,680	9,627	9,271	9,547	8,914	9,186	9,214	9,271	9,587	9,271	9,547	111,703
2018	10,525	9,530	10,570	10,179	10,481	9,797	10,116	10,137	10,135	10,570	10,179	10,481	122,699
2019	11,461	10,375	11,461	11,129	11,461	10,681	11,056	11,056	11,038	11,506	11,084	11,415	133,723
2020	12,396	11,220	12,396	12,035	12,349	11,592	11,980	11,963	12,035	12,443	11,942	12,396	144,748
2021	13,292	12,085	13,404	12,964	13,236	12,486	12,896	12,896	12,908	13,348	12,908	13,348	155,772
2022	14,225	12,929	14,339	13,869	14,168	13,388	13,795	13,838	13,812	14,282	13,812	14,339	166,796
2023	15,230	13,789	15,293	14,728	15,166	14,283	14,717	14,763	14,728	15,230	14,728	15,166	177,819
2024	16,163	14,632	16,163	15,695	16,163	15,147	15,680	15,680	15,566	16,227	15,631	16,098	188,843
2025	17,095	15,474	17,095	16,598	17,095	16,062	16,604	16,582	16,534	17,160	16,469	17,095	199,865
2026	18,035	16,325	18,035	17,511	17,967	16,959	17,528	17,502	17,511	18,104	17,374	18,035	210,887
2027	18,913	17,195	19,072	18,446	18,833	17,854	18,439	18,439	18,367	18,992	18,367	18,992	221,910
2028	19,856	18,059	20,031	19,286	19,856	18,758	19,328	19,389	19,286	19,943	19,286	19,856	232,931
2029	20,873	18,899	20,961	20,186	20,786	19,632	20,271	20,314	20,098	20,961	20,186	20,786	243,952

Commercial Building Efficiency
(MWh including losses)

	Energy Reductions												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	3,898	3,481	3,843	3,722	3,926	3,884	4,014	4,014	3,750	3,870	3,750	3,870	46,024
2011	8,157	7,283	8,037	7,786	8,217	8,121	8,388	8,392	7,846	8,097	7,846	8,037	96,206
2012	12,679	11,405	12,588	12,285	12,770	12,725	13,147	13,152	12,376	12,588	12,285	12,770	150,769
2013	17,282	15,543	17,282	16,617	17,282	17,323	17,911	17,911	16,872	17,154	16,745	17,409	205,331
2014	21,893	19,688	21,893	21,047	21,893	21,937	22,671	22,661	21,213	21,726	21,380	21,893	259,894
2015	26,489	23,821	26,489	25,465	26,691	26,540	27,424	27,428	25,465	26,287	25,869	26,489	314,457
2016	31,288	27,934	30,829	29,864	31,518	31,151	32,173	32,191	30,093	31,058	30,093	30,829	369,020
2017	35,621	32,042	35,366	34,514	35,877	35,757	36,930	36,950	34,514	35,621	34,514	35,877	423,583
2018	40,210	36,170	39,921	38,959	40,499	40,355	41,695	41,710	39,248	39,921	38,959	40,499	478,145
2019	44,835	40,325	44,835	43,111	44,835	44,944	46,469	46,469	43,774	44,503	43,442	45,167	532,708
2020	49,470	44,488	49,470	47,558	49,846	49,565	51,216	51,224	47,558	49,093	48,311	49,470	587,271
2021	54,363	48,552	53,588	51,909	54,750	54,170	55,979	55,979	52,297	53,975	52,297	53,975	641,834
2022	59,045	52,716	58,178	56,357	59,479	58,786	60,715	60,749	56,791	58,612	56,791	58,178	696,397
2023	63,152	56,807	62,699	61,188	63,606	63,392	65,472	65,508	61,188	63,152	61,188	63,606	750,959
2024	67,796	60,976	67,796	65,189	67,796	67,961	70,267	70,267	66,191	67,295	65,690	68,297	805,522
2025	72,451	65,155	72,451	69,651	72,451	72,597	75,027	74,994	70,203	71,900	70,754	72,451	860,085
2026	77,047	69,288	77,047	74,070	77,634	77,195	79,767	79,779	74,070	76,461	75,243	77,047	914,648
2027	82,091	73,316	80,921	78,386	82,677	81,800	84,532	84,532	78,971	81,506	78,971	81,506	969,211
2028	86,628	77,394	85,430	83,350	86,628	86,422	89,258	89,307	83,350	86,029	83,350	86,628	1,023,773
2029	90,683	81,571	90,032	87,863	91,334	91,010	94,032	94,066	88,514	90,032	87,863	91,334	1,078,336

Industrial Program
(MWh including losses)

						Energy Reductions							
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	3,663	3,272	3,611	3,498	3,689	3,650	3,772	3,772	3,524	3,637	3,524	3,637	43,251
2011	7,240	6,464	7,134	6,911	7,293	7,208	7,445	7,449	6,964	7,187	6,964	7,134	85,393
2012	10,445	9,396	10,370	10,120	10,520	10,483	10,831	10,835	10,195	10,370	10,120	10,520	124,208
2013	13,721	12,341	13,721	13,193	13,721	13,754	14,221	14,221	13,396	13,619	13,294	13,822	163,023
2014	17,002	15,290	17,002	16,345	17,002	17,037	17,607	17,599	16,475	16,873	16,604	17,002	201,838
2015	20,272	18,230	20,272	19,489	20,426	20,311	20,987	20,991	19,489	20,118	19,797	20,272	240,653
2016	23,695	21,155	23,347	22,617	23,869	23,591	24,365	24,379	22,790	23,521	22,790	23,347	279,468
2017	26,766	24,077	26,574	25,934	26,958	26,868	27,750	27,765	25,934	26,766	25,934	26,958	318,283
2018	30,030	27,013	29,815	29,096	30,246	30,139	31,139	31,151	29,312	29,815	29,096	30,246	357,098
2019	33,322	29,970	33,322	32,040	33,322	33,403	34,536	34,536	32,533	33,075	32,287	33,568	395,913
2020	36,620	32,932	36,620	35,205	36,899	36,691	37,913	37,918	35,205	36,341	35,763	36,620	434,728
2021	40,109	35,821	39,537	38,298	40,395	39,967	41,301	41,301	38,584	39,823	38,584	39,823	473,543
2022	43,441	38,784	42,803	41,464	43,760	43,251	44,670	44,694	41,783	43,122	41,783	42,803	512,358
2023	46,351	41,694	46,018	44,910	46,684	46,527	48,054	48,080	44,910	46,351	44,910	46,684	551,173
2024	49,656	44,661	49,656	47,746	49,656	49,776	51,466	51,466	48,481	49,289	48,113	50,023	589,988
2025	52,968	47,634	52,968	50,922	52,968	53,075	54,852	54,828	51,325	52,565	51,728	52,968	628,803
2026	56,238	50,575	56,238	54,065	56,666	56,346	58,223	58,232	54,065	55,810	54,921	56,238	667,618
2027	59,834	53,439	58,981	57,134	60,261	59,622	61,613	61,613	57,560	59,408	57,560	59,408	706,433
2028	63,060	56,338	62,188	60,674	63,060	62,910	64,974	65,010	60,674	62,624	60,674	63,060	745,248
2029	65,936	59,311	65,463	63,886	66,410	66,174	68,371	68,396	64,359	65,463	63,886	66,410	784,063

Irrigation Efficiency Program
(MWh including losses)

						Energy Reductions							
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	0	0	0	499	1,831	2,486	2,659	2,244	1,146	225	0	0	11,090
2011	0	0	0	998	3,662	4,973	5,319	4,487	2,291	450	0	0	22,180
2012	0	0	0	1,447	5,310	7,210	7,712	6,506	3,322	653	0	0	32,161
2013	0	0	0	1,846	6,775	9,200	9,840	8,301	4,239	833	0	0	41,033
2014	0	0	0	2,196	8,056	10,940	11,701	9,871	5,041	991	0	0	48,796
2015	0	0	0	2,455	9,008	12,233	13,084	11,038	5,636	1,108	0	0	54,563
2016	0	0	0	2,715	9,960	13,526	14,467	12,205	6,232	1,225	0	0	60,330
2017	0	0	0	2,974	10,913	14,819	15,850	13,371	6,828	1,342	0	0	66,096
2018	0	0	0	3,234	11,865	16,112	17,233	14,538	7,423	1,459	0	0	71,863
2019	0	0	0	3,493	12,817	17,405	18,616	15,705	8,019	1,576	0	0	77,630
2020	0	0	0	3,753	13,769	18,698	19,999	16,871	8,615	1,693	0	0	83,397
2021	0	0	0	4,012	14,721	19,990	21,381	18,038	9,211	1,810	0	0	89,164
2022	0	0	0	4,272	15,673	21,283	22,764	19,204	9,806	1,927	0	0	94,930
2023	0	0	0	4,531	16,625	22,576	24,147	20,371	10,402	2,044	0	0	100,697
2024	0	0	0	4,791	17,577	23,869	25,530	21,538	10,998	2,161	0	0	106,464
2025	0	0	0	5,050	18,529	25,162	26,913	22,704	11,593	2,278	0	0	112,231
2026	0	0	0	5,310	19,481	26,455	28,296	23,871	12,189	2,395	0	0	117,998
2027	0	0	0	5,569	20,434	27,748	29,679	25,038	12,785	2,512	0	0	123,764
2028	0	0	0	5,829	21,386	29,041	31,062	26,204	13,381	2,629	0	0	129,531
2029	0	0	0	6,088	22,338	30,334	32,444	27,371	13,976	2,747	0	0	135,298

Energy Efficiency Programs—Total

(MWh including losses)

	Energy Reductions												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2010	9,620	8,624	9,529	9,727	11,496	11,873	12,359	11,943	10,418	9,799	9,273	9,574	124,236
2011	18,807	16,846	18,609	19,019	22,569	23,406	24,351	23,536	20,412	19,158	18,121	18,609	243,442
2012	27,668	24,915	27,521	28,246	33,125	34,564	35,972	34,782	30,268	28,174	26,799	27,815	359,849
2013	36,664	33,009	36,664	37,154	43,438	45,465	47,342	45,803	39,960	37,290	35,514	36,870	475,173
2014	45,676	41,116	45,676	46,171	53,732	56,157	58,434	56,578	49,287	46,396	44,516	45,676	589,415
2015	54,472	49,032	54,472	54,896	63,807	66,215	68,866	66,817	58,077	55,253	53,094	54,472	699,471
2016	63,596	56,917	62,857	63,592	73,925	76,291	79,274	77,067	67,479	64,451	61,247	62,857	809,553
2017	71,975	64,799	71,567	72,693	83,295	86,357	89,715	87,300	76,546	73,316	69,719	72,382	919,665
2018	80,766	72,712	80,305	81,468	93,090	96,402	100,183	97,535	86,118	81,764	78,234	81,226	1,029,805
2019	89,617	80,670	89,617	89,773	102,434	106,432	110,677	107,766	95,364	90,661	86,812	90,150	1,139,974
2020	98,486	88,641	98,486	98,552	112,863	116,545	121,108	117,976	103,414	99,571	96,016	98,486	1,250,144
2021	107,764	96,458	106,529	107,184	123,102	126,614	131,557	128,213	113,000	108,956	103,789	107,146	1,360,313
2022	116,711	104,429	115,320	115,962	133,080	136,708	141,945	138,485	122,192	117,943	112,385	115,320	1,470,481
2023	124,733	112,289	124,011	125,357	142,081	146,778	152,391	148,723	131,228	126,777	120,826	125,455	1,580,649
2024	133,615	120,269	133,615	133,421	151,192	156,753	162,943	158,950	141,236	134,972	129,434	134,419	1,690,817
2025	142,515	128,264	142,515	142,222	161,044	166,897	173,396	169,108	149,655	143,903	138,951	142,515	1,800,984
2026	151,321	136,188	151,321	150,956	171,748	176,956	183,814	179,383	157,835	152,770	147,538	151,321	1,911,151
2027	160,839	143,950	158,974	159,536	182,204	187,025	194,262	189,621	167,683	162,419	154,898	159,906	2,021,318
2028	169,544	151,791	167,648	169,139	190,929	197,130	204,622	199,909	176,691	171,226	163,310	169,544	2,131,484
2029	177,493	159,781	176,456	178,023	200,868	207,150	215,119	210,147	186,948	179,202	171,935	178,530	2,241,649

Residential Programs

(MW including losses)

	Peak Demand Reductions												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2010	3	3	3	3	3	3	3	3	3	3	3	3	3
2011	5	5	5	5	5	4	4	4	5	5	5	5	5
2012	6	6	6	6	6	6	6	6	6	6	6	6	6
2013	8	8	8	8	8	7	7	7	8	8	8	8	8
2014	9	9	9	9	9	9	9	9	9	9	9	9	9
2015	10	10	10	10	10	10	10	10	10	10	10	10	10
2016	12	11	12	12	12	11	11	11	12	12	12	12	12
2017	13	13	13	13	13	12	12	12	13	13	13	13	13
2018	14	14	14	14	14	14	14	14	14	14	14	14	14
2019	15	15	15	15	15	15	15	15	15	15	15	15	15
2020	17	16	17	17	17	16	16	16	17	17	17	17	17
2021	18	18	18	18	18	17	17	17	18	18	18	18	18
2022	19	19	19	19	19	19	19	19	19	19	19	19	19
2023	20	21	21	20	20	20	20	20	20	20	20	20	21
2024	22	21	22	22	22	21	21	21	22	22	22	22	22
2025	23	23	23	23	23	22	22	22	23	23	23	23	23
2026	24	24	24	24	24	24	24	24	24	24	24	24	24
2027	25	26	26	26	25	25	25	25	26	26	25	26	26
2028	27	26	27	27	27	26	26	26	27	27	27	27	27
2029	28	28	28	28	28	27	27	27	28	28	28	28	28

Commercial Programs
(MW including losses)

					Peak Demand Reductions							
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2010	5	5	5	5	5	5	5	5	5	5	5	5	5
2011	11	11	11	11	11	11	11	11	11	11	11	11	11
2012	17	16	17	17	17	18	18	18	17	17	17	17	18
2013	23	23	23	23	23	24	24	24	23	23	23	23	24
2014	29	29	29	29	29	30	30	30	29	29	30	29	30
2015	36	35	36	35	36	37	37	37	35	35	36	36	37
2016	42	40	41	41	42	43	43	43	42	42	42	41	43
2017	48	48	48	48	48	50	50	50	48	48	48	48	50
2018	54	54	54	54	54	56	56	56	55	54	54	54	56
2019	60	60	60	60	60	62	62	62	61	60	60	61	62
2020	66	64	67	66	67	69	69	69	66	66	67	66	69
2021	73	72	72	72	74	75	75	75	73	73	73	73	75
2022	79	78	78	78	80	82	82	82	79	79	79	78	82
2023	85	85	84	85	85	88	88	88	85	85	85	85	88
2024	91	88	91	91	91	94	94	94	92	90	91	92	94
2025	97	97	98	97	97	101	101	101	98	97	98	97	101
2026	104	103	104	103	104	107	107	107	103	103	104	104	107
2027	110	109	109	109	111	114	114	114	110	110	110	110	114
2028	116	111	115	116	116	120	120	120	116	116	116	116	120
2029	122	121	121	122	123	126	126	126	123	121	122	123	126

Industrial Program
(MW including losses)

					Peak Demand Reductions							
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Max**
2010	5	5	5	5	5	5	5	5	5	5	5	5	5
2011	10	10	10	10	10	10	10	10	10	10	10	10	10
2012	14	14	14	14	14	15	15	15	14	14	14	14	15
2013	18	18	18	18	18	19	19	19	19	18	18	19	19
2014	23	23	23	23	23	24	24	24	23	23	23	23	24
2015	27	27	27	27	27	28	28	28	27	27	27	27	28
2016	32	30	31	31	32	33	33	33	32	32	32	31	33
2017	36	36	36	36	36	37	37	37	36	36	36	36	37
2018	40	40	40	40	41	42	42	42	41	40	40	41	42
2019	45	45	45	45	45	46	46	46	45	44	45	45	46
2020	49	47	49	49	50	51	51	51	49	49	50	49	51
2021	54	53	53	53	54	56	56	56	54	54	54	54	56
2022	58	58	58	58	59	60	60	60	58	58	58	58	60
2023	62	62	62	62	63	65	65	65	62	62	62	63	65
2024	67	64	67	66	67	69	69	69	67	66	67	67	69
2025	71	71	71	71	71	74	74	74	71	71	72	71	74
2026	76	75	76	75	76	78	78	78	75	75	76	76	78
2027	80	80	79	79	81	83	83	83	80	80	80	80	83
2028	85	81	84	84	85	87	87	87	84	84	84	85	87
2029	89	88	88	89	89	92	92	92	89	88	89	89	92

Irrigation Efficiency Program
(MW including losses)

Peak Demand Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2010	0	0	0	1	2	3	4	3	2	0	0	0	4
2011	0	0	0	1	5	7	7	6	3	1	0	0	7
2012	0	0	0	2	7	10	10	9	5	1	0	0	10
2013	0	0	0	3	9	13	13	11	6	1	0	0	13
2014	0	0	0	3	11	15	16	13	7	1	0	0	16
2015	0	0	0	3	12	17	18	15	8	1	0	0	18
2016	0	0	0	4	13	19	19	16	9	2	0	0	19
2017	0	0	0	4	15	21	21	18	9	2	0	0	21
2018	0	0	0	4	16	22	23	20	10	2	0	0	23
2019	0	0	0	5	17	24	25	21	11	2	0	0	25
2020	0	0	0	5	19	26	27	23	12	2	0	0	27
2021	0	0	0	6	20	28	29	24	13	2	0	0	29
2022	0	0	0	6	21	30	31	26	14	3	0	0	31
2023	0	0	0	6	22	31	32	27	14	3	0	0	32
2024	0	0	0	7	24	33	34	29	15	3	0	0	34
2025	0	0	0	7	25	35	36	31	16	3	0	0	36
2026	0	0	0	7	26	37	38	32	17	3	0	0	38
2027	0	0	0	8	27	39	40	34	18	3	0	0	40
2028	0	0	0	8	29	40	42	35	19	4	0	0	42
2029	0	0	0	8	30	42	44	37	19	4	0	0	44

Energy Efficiency Programs—Total
(MW including losses)

Peak Demand Reductions													
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Max
2010	13	13	13	14	15	16	17	16	14	13	13	13	17
2011	25	25	25	26	30	33	33	32	28	26	25	25	33
2012	37	36	37	39	45	48	48	47	42	38	37	37	48
2013	49	49	49	52	58	63	64	62	56	50	49	50	64
2014	61	61	61	64	72	78	79	76	68	62	62	61	79
2015	73	73	73	76	86	92	93	90	81	74	74	73	93
2016	85	82	85	88	99	106	107	104	94	87	85	84	107
2017	97	96	96	101	112	120	121	117	106	99	97	97	121
2018	109	108	108	113	125	134	135	131	120	110	109	109	135
2019	120	120	121	125	138	148	149	145	132	122	120	121	149
2020	132	127	133	137	152	162	163	159	144	134	133	132	163
2021	145	144	143	149	165	176	177	172	157	146	144	144	177
2022	157	155	155	161	179	190	191	186	170	159	156	155	191
2023	168	167	167	174	191	204	205	200	182	170	168	169	205
2024	180	173	180	185	203	218	219	214	196	181	180	181	219
2025	192	191	192	198	216	232	233	227	208	193	193	192	233
2026	203	203	204	210	231	246	247	241	219	205	205	203	247
2027	216	214	214	222	245	260	261	255	233	218	215	215	261
2028	228	218	226	235	257	274	275	269	245	230	227	228	275
2029	239	238	237	247	270	288	289	282	260	241	238	240	289

This page left blank intentionally.