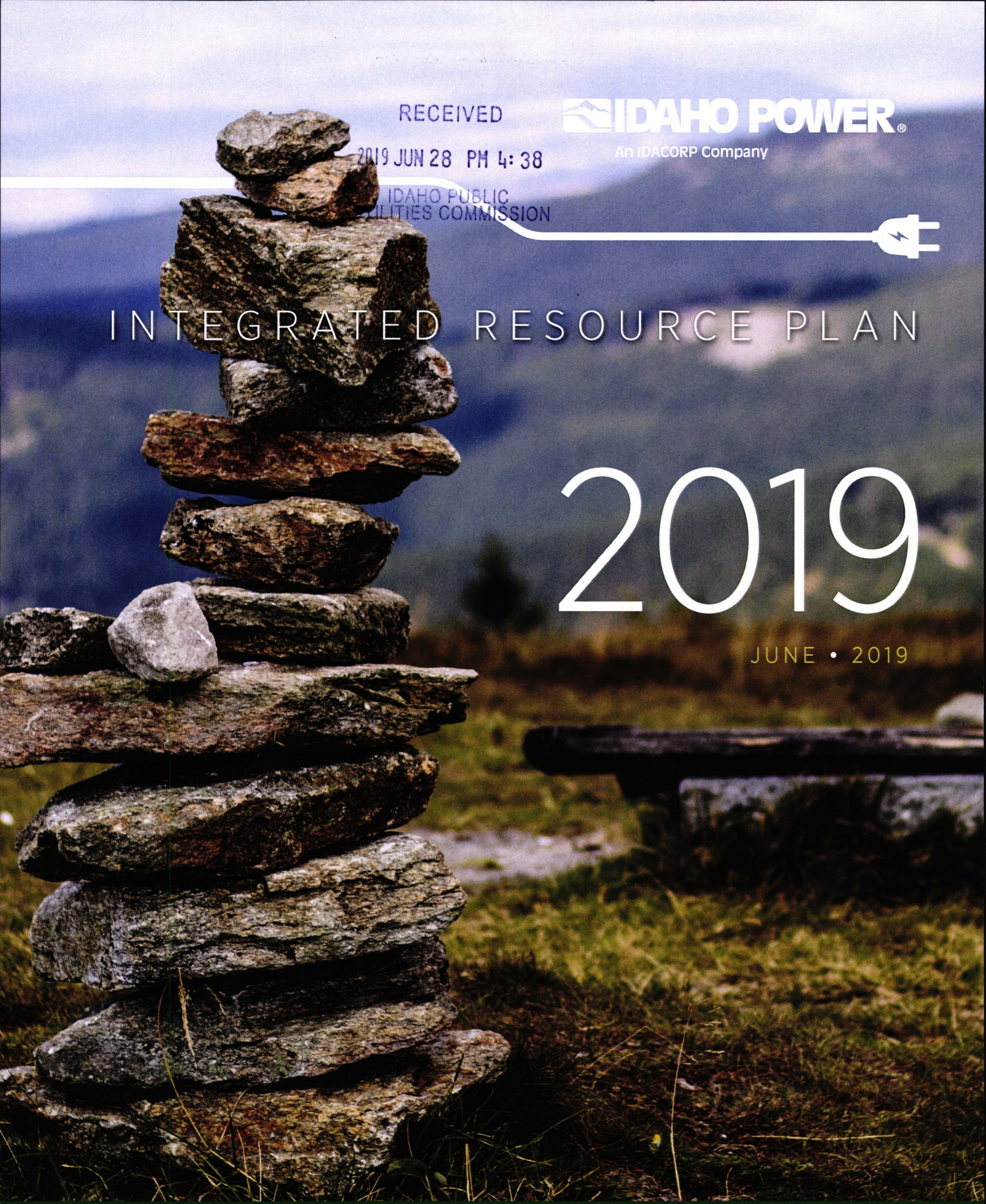

IDAHO POWER®
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INTEGRATED RESOURCE PLAN

2019

JUNE • 2019

APPENDIX A: SALES AND LOAD FORECAST

SAFE HARBOR STATEMENT

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INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2019 Integrated Resource Plan* (IRP). Appendix A includes details on the energy sales and load forecast of future demand for electricity within the company's service area. The above-mentioned forecast covers a 20-year period from 2019 through 2038.

This appendix describes the development of the expected-case monthly average sales forecast. The forecast is Idaho Power's estimate of the most probable outcome for sales growth during the 20- year planning period. In addition, to account for inherent uncertainty in the forecast, additional forecast cases are prepared to test ranges of variability to the expected case.

Economic and demographic (non-weather-related) assumptions are modified to create scenarios for a low and a high economic-related case. By holding weather variability constant, these forecasts test the assumptions of the expected case economic/demographic variables by applying historically-based parameters of growth on both the low and high side of the economic determinants of the expected case forecast.

Economic data in the forecast models is primarily sourced from Moody's Analytics. The national, state, metropolitan service area (MSA), and county economic and demographic projections are tailored to Idaho Power's service area using an in-house historic economic database. Specific demographic projections are also developed for the service area from national and local census data. Additional data sources used to substantiate Moody's data include the Idaho Department of Labor, Woods & Poole, Construction Monitor, and Federal Reserve economic databases.

As economic growth assumptions influence several classes of service growth rates it is important to review several key components. The number of households in Idaho is projected to grow at an annual rate of 1.3 percent during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area is projected to grow faster than the remainder of the state over the planning period. Similarly, the number of households in the Boise–Nampa MSA is projected to grow faster than the state of Idaho as well, at an annual rate of 1.6 percent during the forecast period. The Boise MSA (or the Treasure Valley) is an area that encompasses Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho.
In addition to the number of households, incomes, employment, economic output, and real retail electricity prices are used to develop load projections.

Scenarios of weather related influence on potential ranges of the expected-case forecast are tested utilizing a probabilistic 70% and 90% distribution of normal weather (temperature and precipitation) applied to the weather assumptions in the expected case. This provides a comparative range of outcome that isolates long-term sustained weather influences on the forecast.

The forecast of the expected-case scenario shows, Idaho Power's system load is forecast to increase to 2,212 average megawatts (aMW) by 2038 from 1,833 aMW in 2019, representing an average yearly growth rate of 1.0 percent over the 20-year planning period (2019–2038).
A similar annual average growth rate in system load is reflected in both weather-related

scenarios (70th-percentile and 90th-percentile). From an annual peak-hour demand perspective, the expected case of the peak demand forecast will grow to 4,388 megawatts (MW) in 2038 from the all-time system peak of 3,422 MW that occurred on Friday, July 7, 2017, at 5:00 p.m. Idaho Power's system peak increases at an average growth rate of 1.2 percent per year over the 20-year planning period (2019–2038) under this case. Over this same term, the number of Idaho Power active retail customers is expected to increase from the December 2018 level of 556,400 customers to nearly 775,000 customers by 2038.

Beyond the weather, climate, economic and demographic assumptions used to drive the expected-case forecast scenario, several additional assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors.

Some examples include conservation influences on the load forecast, including Idaho Power energy efficiency demand side management (DSM) programs, statutory programs, and non-programmatic trends in conservation. These influences are included in the load forecasts. Idaho Power DSM programs are described in detail in Idaho Power's Demand-Side Management 2018 Annual Report, which is incorporated into this IRP document as Appendix B. Idaho Power also recognizes the impact of on-site generation and electric vehicles in its service territory and does include the energy reduction or addition in the long-term sales and load forecast due to their impact. Further discussions of these assumptions are presented in the appropriate section.

Potential risks during the 20-year forecast horizon include major shifts in the electric utility industry (e.g., state and federal regulations and varying electricity prices) which could influence the load forecast. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The uncertainty associated with such changes is reflected in the economic high and low load growth scenarios described previously.
The alternative sales and load scenarios in Appendix A—Sales and Load Forecast were prepared under the assumption that Idaho Power's geographic service area remains unchanged during the planning period.

Data describing the historical and projected figures for the sales and load forecast are presented in Appendix A1 of this report.

2019 IRP Sales and Load Forecast

Average Load

The economic and demographic variables driving the 2019 forecast have the impact of increasing current annual sales levels throughout the planning period. The extended business cycle recovery process after the Great Recession in 2008 for the national and service area economy muted load growth post-recession through 2011. However, in 2012, the extended recovery process was evident, and on-balance stronger growth was exhibited in most economic drivers relative to recent history at that time. It is expected that economic conditions return to long-term fundamentals during the 2019 forecast term. Significant factors and considerations that influenced the outcome of the 2019 IRP load forecast include the following:

- Weather plays a primary role in impacting the load forecast on a monthly and seasonal basis. In the expected case load forecast of energy and peak-hour demand, Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period or defined as normal climatology. Probabilistic variations of weather are also analyzed.

- The economic forecast used for the 2019 IRP reflects the continued expansion of the Idaho economy in the near-term and reversion to the long-term trend of the service area economy. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed positive activity. In support, Idaho has been the fastest growth rate state in the US in terms of population—in both the 2017 and 2018 measurement periods. Going into 2017, customer additions have approached sustainable growth rates experienced prior to the housing bubble (2000–2004) and are expected to continue.

- Conservation impacts, including DSM energy efficiency programs, codes and standards, and other naturally occurring efficiencies are integrated into the sales forecast. These impacts are expected to continue to erode use per customer over much of the forecast period. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., demand response is treated as a supply-side peaking resource). 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. Additional impacts from on-site generation customers and electric vehicles are included as well.

- There continues to be significant uncertainty associated with the industrial and special contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an uncertain magnitude of the energy and peak-demand requirements. The expected load forecast reflects only those industrial customers that have made a sufficient and significant binding investment indicating a commitment of the highest probability of locating in the service area. The large numbers of prospective businesses that have indicated an interest in locating in Idaho Power's service area but have not made sufficient commitments are not included in the current sales and load forecast.

- The electricity price forecast used to prepare the sales and load forecast in the 2019 IRP reflects the impact of additional plant investments and associated variable costs of integrating new resources identified in the 2017 IRP preferred portfolio. The two forecasts converge after the 20-year period, although the 2019 IRP price forecast yields higher prices in the near term when compared to the electricity price forecast used to prepare the 2017 IRP sales and load forecast. Retail prices carry an inverse relationship between electricity prices and electricity demand.

Peak-Hour Demands

Average loads, as discussed in the preceding section, are an integral component to the load forecast, as is the impact of the peak-hour demands on the system. Like the sales forecast discussed in the preceding section, the peak models incorporate several peak forecast scenarios based on historical probabilities of peak day temperatures at the 50th, 90th, and 95th-percentiles of occurrence for each month of the year. The peak-hour demands (peaks) are forecasted separately using regressions that are expressed as a function of the sales (average load) forecast as well as the impact of peak-day temperatures, more discussion is provided in forthcoming sections. The peak forecast results and comparisons with previous forecasts differ for many reasons that include the following:

- The all-time system summer peak demand was 3,422 MW (recorded on Friday, July 7, 2017, at 5:00 p.m.). Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9:00 a.m. and matched the previous record peak dated December 10, 2009, at 8:00 a.m.

- The peak model develops peak-scenario impacts based on historical probabilities of peak day temperatures at the 50th, 90th, and 95th-percentiles of occurrence for each month of the year. These average peak-day temperature drivers are calculated over the 1988 to 2017 time period (the most recent 30 years).

- The 2019 IRP peak-demand forecast considers the impact of the current actualized committed and implemented energy efficiency DSM programs on peak demand.

Overview of the Forecast and Scenarios

The sales and load forecast is constructed by developing a separate energy forecast for each of the major customer classes: residential, commercial, irrigation, industrial, and special contracts. In conjunction with this load (or sales) forecast, an hour peak-load (peak) forecast was prepared. In addition, several probability cases were developed for the energy and peak forecasts. Assumptions for each of the individual categories, the peak hour impacts, and probabilistic case methodologies are described in greater detail in the following sections.

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 average 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 and the resulting derived economic forecast for Idaho Power's service area.

The expected-case average load forecast assumes median temperatures and median precipitation (i.e., there is a 50 percent chance 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, alternative scenarios were developed that address load variability due to varying weather conditions.

Illustratively, Idaho Power's maximum annual average 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 annual average load occurs when the opposite of what is described above takes place. In the 70^{th}-percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70^{th}-percentile of HDD in wintertime and at the 70^{th}-percentile of CDD in summertime. In the 70^{th}-percentile irrigation load forecast, GDD were assumed to be at the 70^{th}-percentile and precipitation at the 30^{th}-percentile, reflecting drier-than-median weather. The 90^{th}-percentile load forecast was similarly constructed.

For example, the median HDD in December from 1988 to 2017 (the most recent 30 years) was 1,035, at the Boise Weather Service office. The 70^{th}-percentile HDD is 1,065 and would be exceeded in 3 out of 10 years. The 90^{th}-percentile HDD is 1,188 and would be exceeded in 1 out of 10 years. As an example, for a single month, the 100^{th}-percentile HDD (the coldest December over the 30 years) is 1,449, which occurred in December 1990. This same concept was applied in each month throughout the year for the weather-sensitive customer classes: residential, commercial, and irrigation.

Since Idaho Power loads are highly dependent on weather, and the development of the above mentioned two scenarios allows the 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 each month. This assumes temperatures and precipitation would maintain at the 70th-percentile or 90th-percentile level continuously, throughout the entire year. Table 1 summarizes the load scenarios prepared for the 2019 IRP.

Table 1. 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

Results of Idaho Power's weather related probabilistic system load projections are reported in Table 2 and shown in Figure 1.

Table 2. System load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	1,939	2,035	2,140	2,342	1.0%
70th Percentile	1,878	1,970	2,072	2,267	1.0%
Expected Case	1,833	1,923	2,022	2,212	1.0%

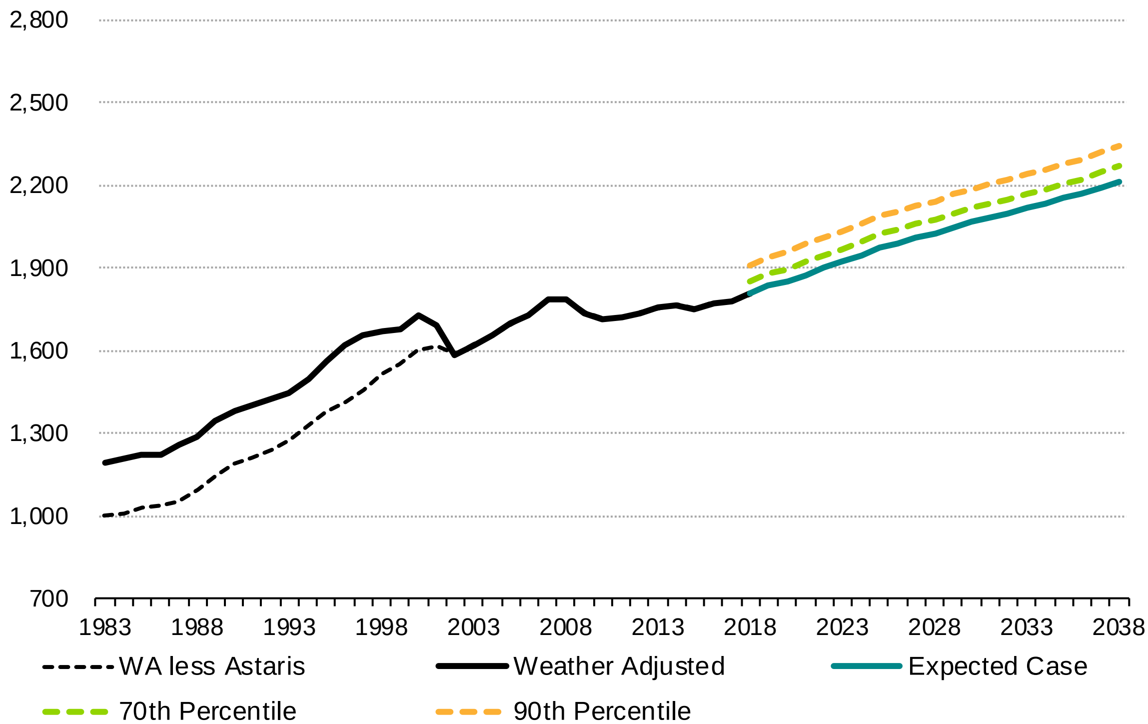

Figure 1. **Forecast system load (aMW)[1]**

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.

To provide risk assessment to economic uncertainty, two additional load forecasts for Idaho Power's service area were prepared based on the expected case forecast. The forecasts provide a range of possible load growth rates for the 2019 to 2038 planning period due to high and low economic and demographic conditions. The average growth rates for these high and low growth scenarios were derived from the historical distribution of one-year growth rates over the past 25 years (1994–2018).

Of the three scenarios 1) the expected forecast is the median growth path, 2) the standard deviation observed during the historical time period is used to estimate the dispersion around the expected-case scenario, and 3) the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1994–2018).

From the above methodology, two views of probable outcomes from the forecast scenarios—the probability of exceeding and the probability of occurrence—were developed and are reported

[1] 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 had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated.

in Table 3. The probability of exceeding the likelihood 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 the actual growth rate will exceed the growth rate projected in the high scenario; additionally, it can be inferred that for the stated periods there is an 80 percent probability the actual growth rate will fall between the low and high scenarios.

The second probability estimate, the probability of occurrence, indicates the likelihood 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 the actual growth rate will be closer to the high scenario than to any other forecast scenario for the entire 20-year planning horizon.

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%

This probabilistic analysis was applied to Idaho Power's system load forecast. Its impact on the system load forecast is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts.

Results of Idaho Power's economic scenario probabilistic system load projections are reported in Table 4 and shown in Figure 2. The expected-case system load-forecast growth rate averages 1.0 percent per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 0.5 percent per year throughout the forecast period. The high scenario projects a load growth of 1.4 percent per year. Idaho Power has experienced both the high- and low-growth rates in the past. These 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 load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
Low	1,789	1,822	1,879	1,986	0.5%
Expected	1,833	1,923	2,022	2,212	1.0%
High	1,878	2,030	2,189	2,465	1.4%

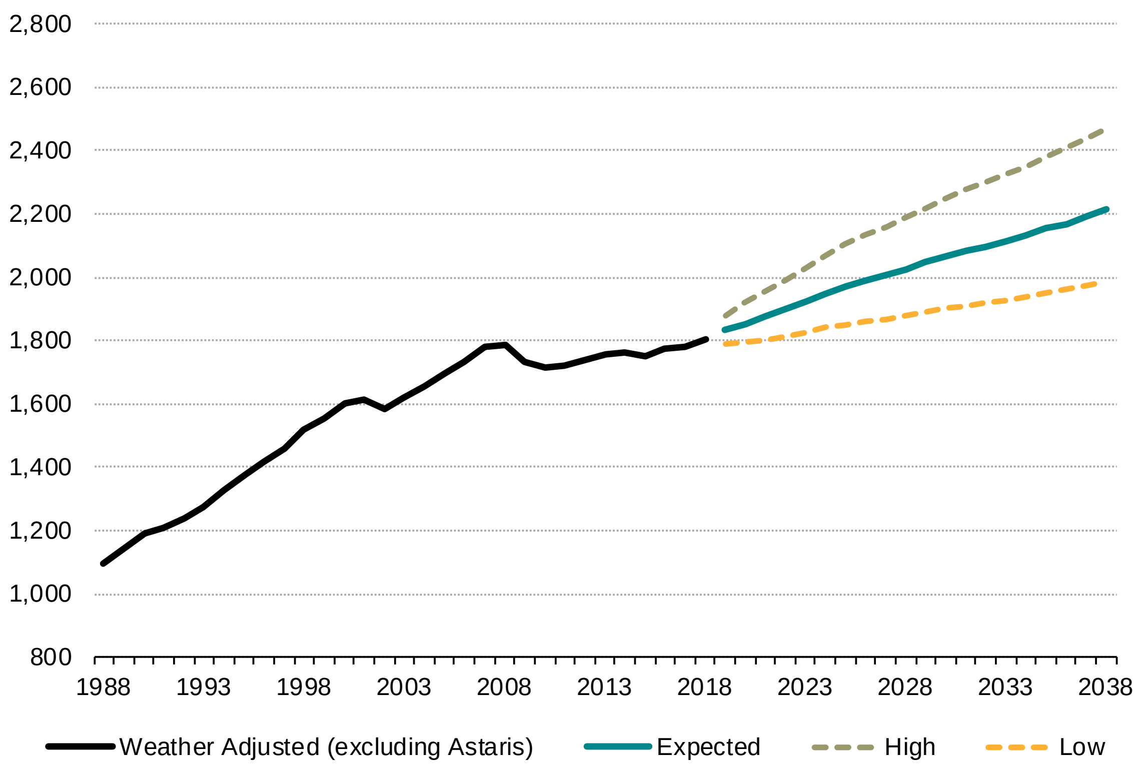

Figure 2. Forecast system load (aMW)

Company System Load

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and on system contracts (including past sales to Raft River and the City of Weiser). The system load excludes all long-term, firm off-system contracts.

The expected-case system load forecast is based on the output of the regression and forecasting models referenced previously and represents Idaho Power's most probable load growth during the planning period. The expected-case forecast system load growth rate averages 1.0 percent per year from 2019 to 2038. Company system load projections are reported in Table 2 and shown in Figure 1.

In the expected-case forecast, the company system load is expected to increase from 1,833 aMW in 2019 to 2,212 aMW in 2038, an average annual growth rate of 1.0 percent. In the weather sensitive scenarios, the 70th-percentile and 90th-percentile forecasts, the company system load is expected to increase from 1,878 aMW in 2019 to 2,267 aMW by 2038, and increase from 1,939 aMW in 2019 to 2,342 aMW, respectively. All represent an average growth rate of 1.0 percent per year over the planning period. In the economic probability scenarios, the company system load is expected to increase in the low case from 1,789 aMW in 2019 to 1,986 aMW in 2038, an average annual growth rate of 0.5 percent and in the high case from 1,838 aMW to 2,465 aMW, an average annual growth rate of 1.4 percent (Table 2).

The system load, excluding Astaris, portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive in regard to the impact of a new significant large-load customer on system load. As noted previously, the forecast excludes any such speculative large-load customers.

Accompanied by an outlook of economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is projected. 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.

The composition of system company electricity sales by year is shown in Figure 3. Residential sales are forecast to be about 23 percent higher in 2038, gaining 1.2 million MWh over 2019. Commercial sales are also expected to be 24 percent higher, or 1.0 million MWh, then in 2019, followed by industrial (11 percent higher, or 0.3 million additional MWh) and irrigation (16 percent higher in 2038 than 2019).

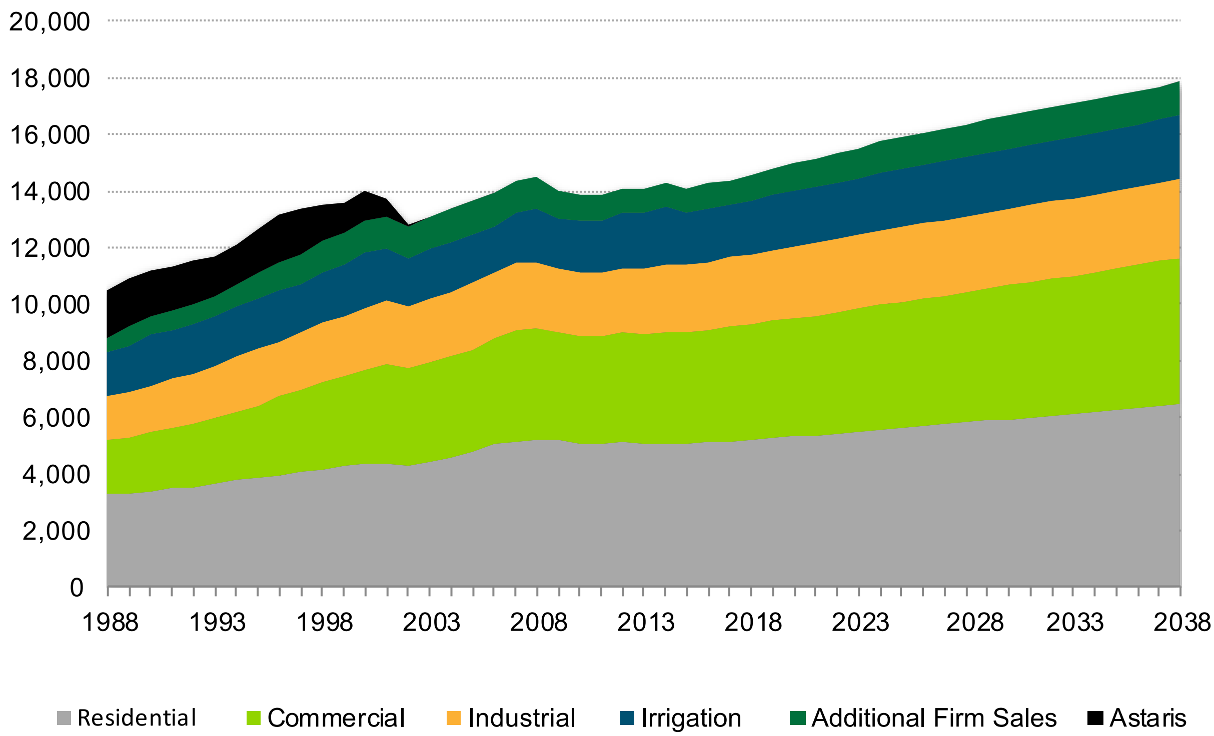

Figure 3. Composition of system company electricity sales (thousands of MWh)

COMPANY SYSTEM PEAK

System peak load includes the sum of the coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts (including Astaris, historically) and on-system contracts (Raft River and the City of Weiser, historically).

Seasonal Peak Forecast

Idaho Power has two peak periods: 1) a winter peak, resulting primarily from space-heating demand that normally occurs in December, January, or February and 2) a larger summer peak that normally occurs in late June, July or August, which coincides with cooling load and irrigation pumping demand. The summer peak is reflective of the annual peak for the Company.

The all-time system summer peak demand was 3,422 MW, recorded on Friday, July 7, 2017, at 5:00 p.m. The system summer peak load growth accelerated from 1998 to 2008 as a record number of residential, commercial, and industrial customers were added to the system and air conditioning (A/C) became standard in nearly all new residential homes and new commercial buildings.

The 95th-percentile forecast, the system summer peak load is expected to increase from 3,634 MW in 2019 to 4,544 MW in 2038. In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,610 MW in 2019 to 4,519 MW in 2038. Finally, the 50th-percentile, or expected case, the system summer peak load increases from 3,479MW in 2019 to 4,388MW in 2038. All of which represent an average summer peak growth rate of 1.2 percent per year over the planning period (Table 5).

Table 5. System summer peak load growth (MW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
95th Percentile	3,634	3,832	4,073	4,544	1.2%
90th Percentile	3,610	3,808	4,048	4,519	1.2%
50th Percentile	3,479	3,677	3,918	4,388	1.2%

The three scenarios of projected system summer peak loads are illustrated in Figure 4. Much of the variation in peak load is due to weather conditions. Note that unique economic events have occurred, as an example in the summer of 2001 the summer peak was dampened by a nearly 30-percent curtailment in irrigation load due a voluntary load reduction program.

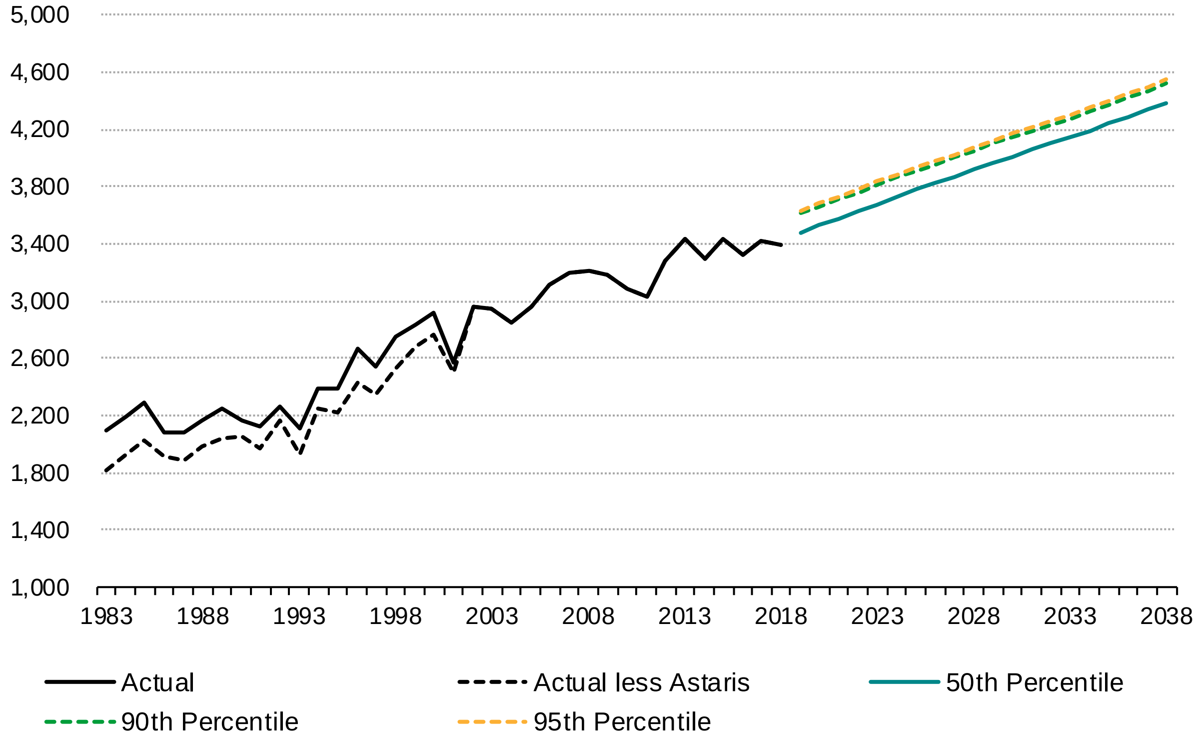

Figure 4. **Forecast system summer peak (MW)**

As of December 31, 2018, the all-time system winter peak demand was 2,527 MW, reached on Thursday, December 10, 2009, at 8:00 a.m. and matched on January 6, 2017, at 9:00 a.m. As shown in Figure 5, the historical system winter peak load is much more variable than the summer system peak load. This is because the variability of peak-day temperatures in winter months is more significant than the variability of peak-day temperatures in summer months. The wider spread of the winter peak forecast lines in Figure 5 illustrates the higher variability associated with winter peak-day temperatures.

In the 95th-percentile forecast, the system winter peak load is expected to increase from 2,636 MW in 2019 to 3,058 MW in 2038, an average growth rate of 0.8 percent per year over the planning period. In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,549 MW in 2019 to 2,998 MW in 2038, an average growth rate of 0.9 percent per year over the planning period. In the 50th-percentile, or expected case forecast, the system winter peak load is expected to increase from 2,390MW in 2019 to 2,887 MW in 2038, an average growth rate of 1.0 percent per year over the planning period. This data is represented in Table 6 below as well as the three scenarios of projected system winter peak load are illustrated in Figure 5.[2]

Table 6. System winter peak load growth (MW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
95th Percentile	2,636	2,735	2,848	3,058	0.8%
90th Percentile	2,549	2,648	2,761	2,998	0.9%
50th Percentile	2,390	2,500	2,635	2,887	1.0%

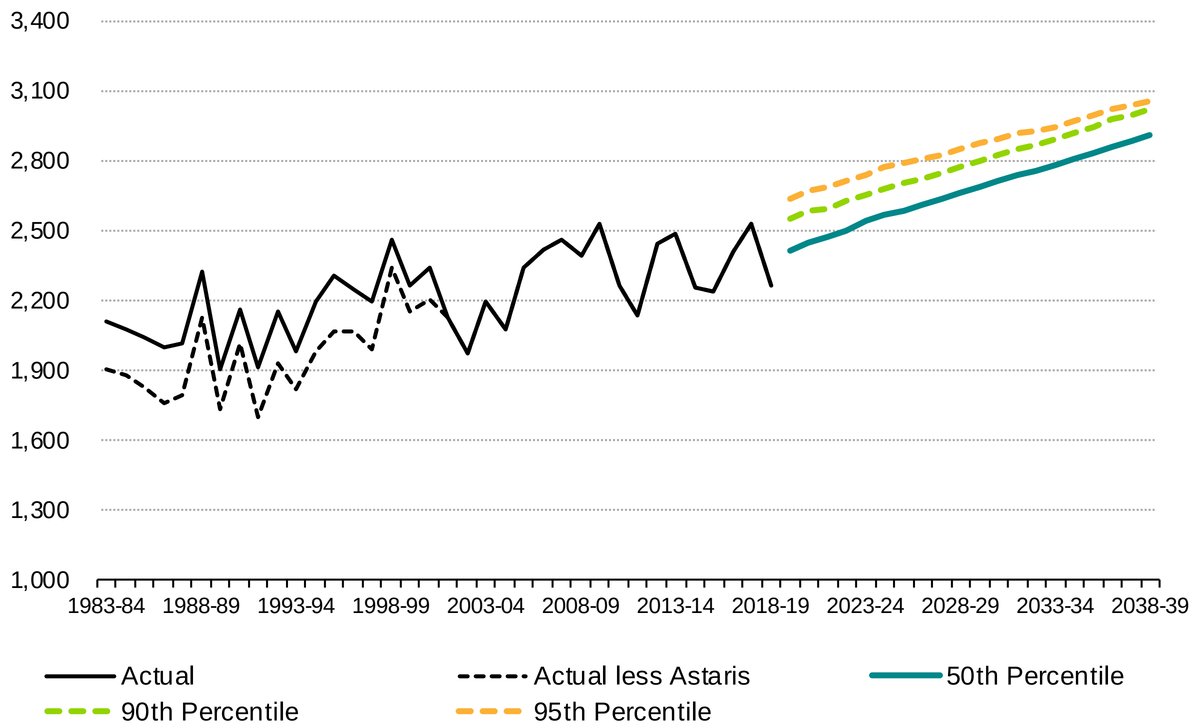

Figure 5. Forecast system winter peak (MW)

Combining the historic relationship of summer and winter peaks as depicted in Figure 6 the growth in the summer peak over the past several decades in Idaho Power's service territory has been much stronger with an increased presence of cooling load in the peak summer months.

[2] Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50/50 peak-demand forecast scenario. 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 within the context of probabilistic percentiles. The weighted average peak-day temperature drivers are calculated over the 1988 to 2017 time period (the most recent 30 years).

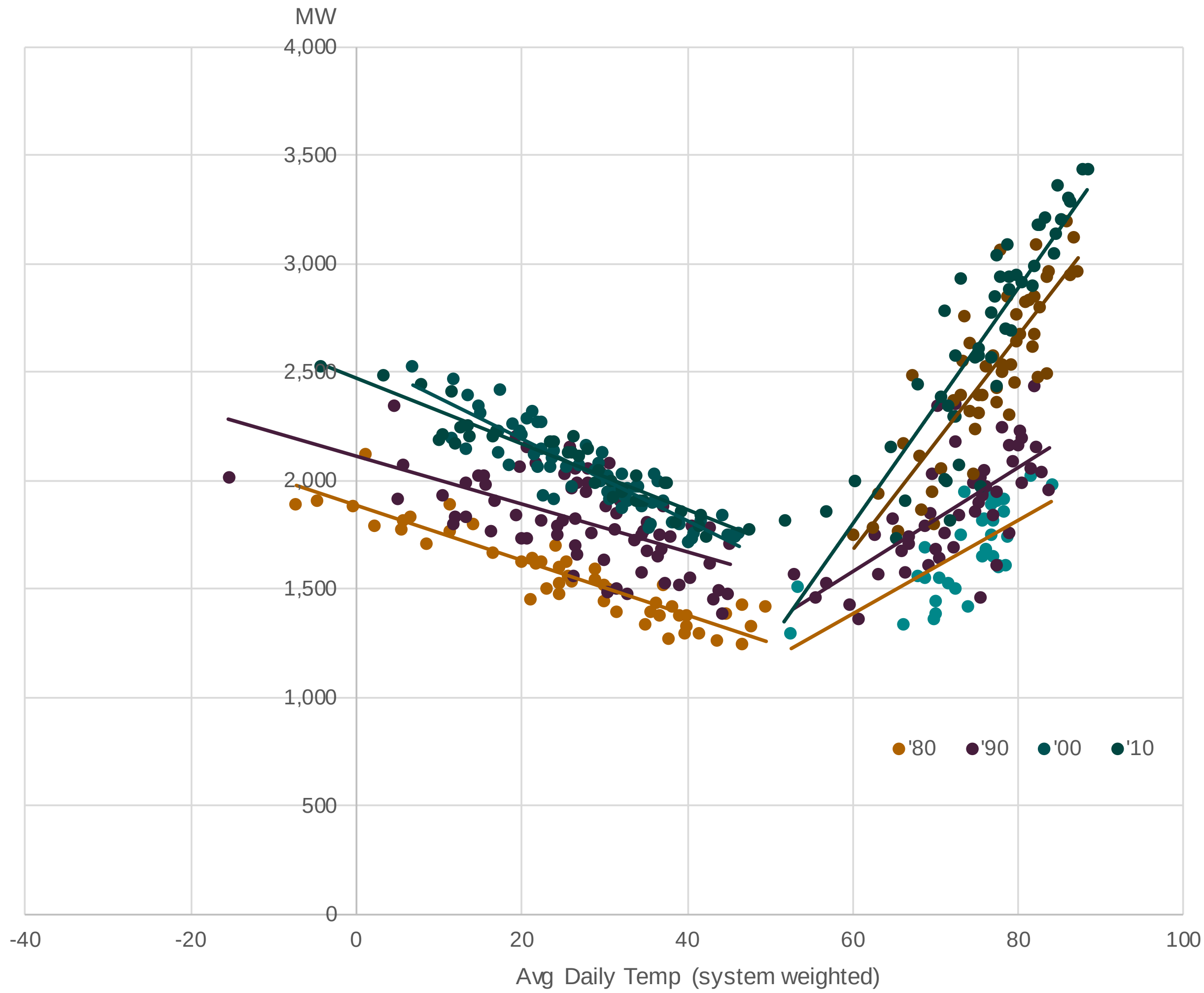

Figure 6. Idaho Power monthly peaks (MW)

Additionally, note the 2019 IRP peak-demand forecast model explicitly excludes the impact of demand response programs to establish peak impacts. The exclusion allows for planning for demand response programs and supply-side resources in meeting peak demand. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

Peak Model Design

Peak-hour demands are integral components to the Company's system planning. Peak-hour demands are forecast using a system of 12 regression equations, one for each month of the year. For most monthly models the regressions are estimated using 25 years of historical data, however, the estimation periods vary. The peak-hour forecasting regressions express system peak-hour demand as a function of calendar sales (stated in average megawatts) as well as the impact of peak-day temperatures, real electricity prices, and in some months precipitation. The contribution to the system peak of the Company's three special contract customers is determined independently, using historical coincident peak factors, and then added to determine the system peak.

The forecast of average peak-day temperatures is a key driver of the monthly system peak models. The normal average peak-day temperature drivers are calculated over the 1988 to 2017 period (the most recent 30 years). In addition, the peak model develops peak-scenarios based on historical probabilities of peak day temperatures at the 50th, 90th, and 95th percentiles of occurrence for each month of the year.

Note the summertime (June, July, and August) system peak regression models were re-specified to account for the upward trend in weighted average peak-day temperatures over time.
The trendlines were fitted to the historical weighted average peak-day temperatures and then projected through the end of the forecast period, the year 2038. These are added as explanatory variables in the summertime regression models. The addition of these variables resulted in models that better fit the actual historical summertime system peaks.

Class Sales Forecasts

Residential

The expected-case residential load is forecast to increase from 601 aMW in 2019 to 742 aMW in 2038, an average annual compound growth rate of 1.1 percent. In the 70th-percentile scenario, the residential load is forecast to increase from 621 aMW in 2019 to 769 aMW in 2038, an average annual compound growth rate of 1.1 percent, matching the expected-case residential growth rate (1.1 percent average annual growth). The residential load forecasts are reported in Table 7 and shown in Figure 7.

Table 7. Residential load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	649	680	718	806	1.1%
70th Percentile	621	650	685	769	1.1%
Expected Case	601	628	662	742	1.1%

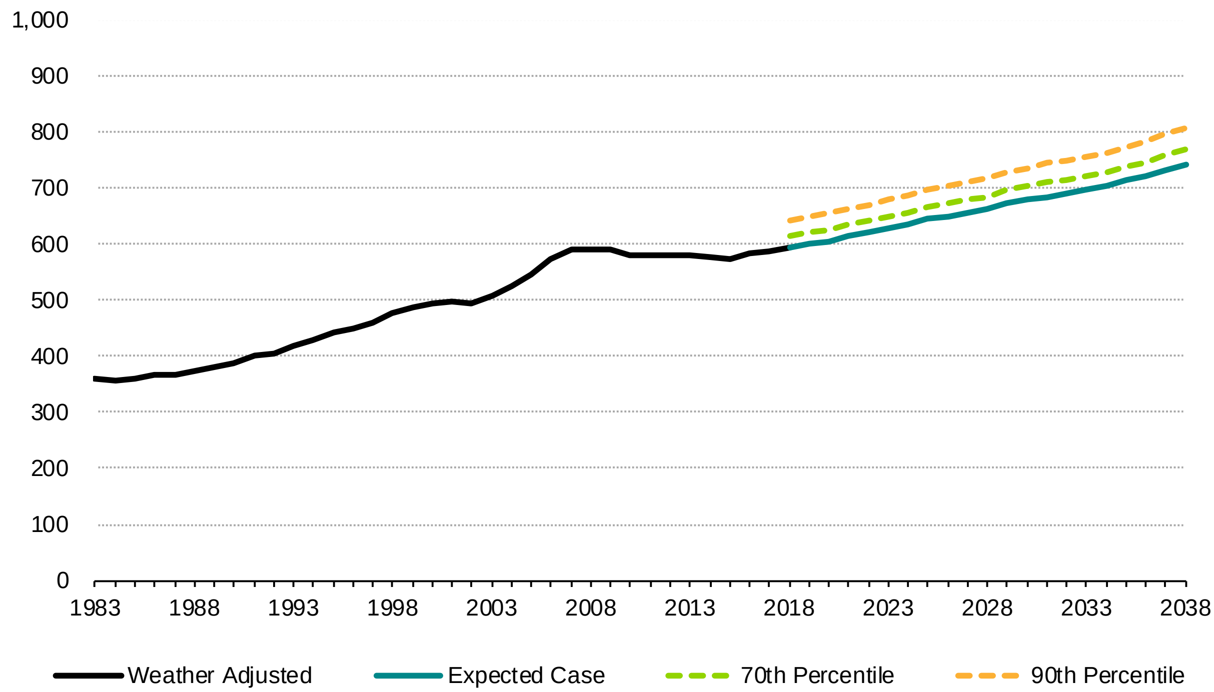

Figure 7. Forecast residential load (aMW)

Sales to residential customers made up 31 percent of Idaho Power's system sales in 1988 and 36 percent of system sales in 2018. The number of residential customers is projected to increase to approximately 649,000 by December 2038.

The average sales per residential customer increased to nearly 14,850 kilowatt-hours (kWh) in 1980 before declining to 13,200 kWh in 2001. In 2002 and 2003, residential use per customer dropped dramatically—nearly 500 kWh per customer from 2001—the result of two years of significantly higher electricity prices in those years 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 through 2007. However, conservation efforts places downward pressure on residential use per customer since that point. This trend is expected to continue, ranging at an approximate decline of up to 0.5 percent–1.0 percent per year, as the average sales per residential customer are expected to decrease to approximately 10,100 kWh per year by 2038. Average annual sales per residential customer are shown in Figure 8.

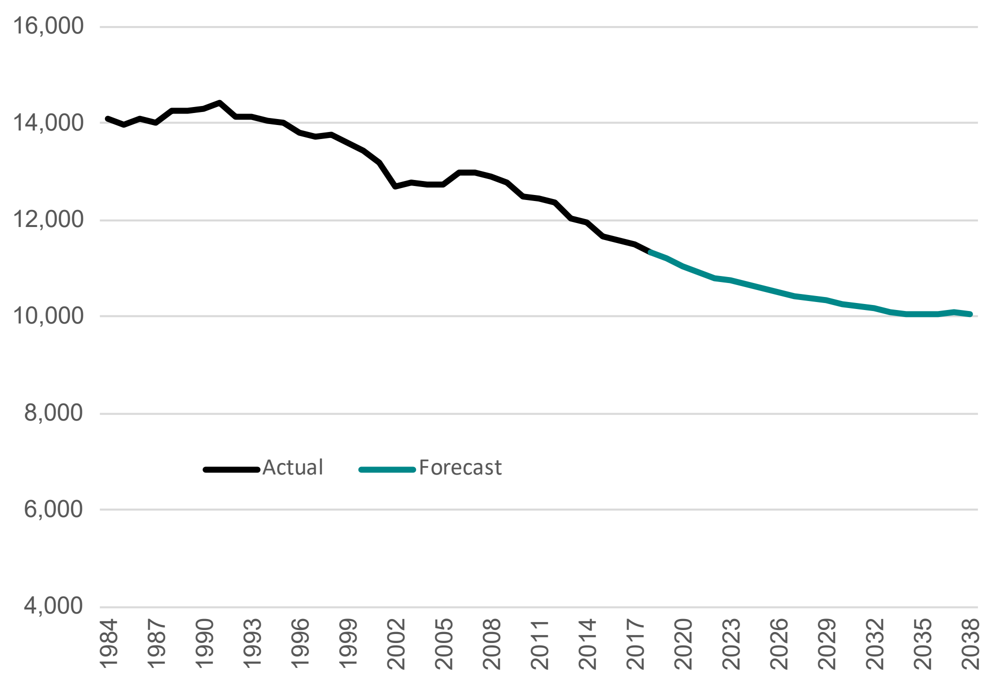

Figure 8. Forecast residential use per customer (weather-adjusted kWh)

Residential customer growth in Idaho Power's service area is a function of the number of new service-area households as derived from Moody's Analytics' forecast of county housing stock and demographic data. The residential-customer forecast for 2019 to 2038 shows an average annual growth rate of 1.7 percent as shown in Figure 9.

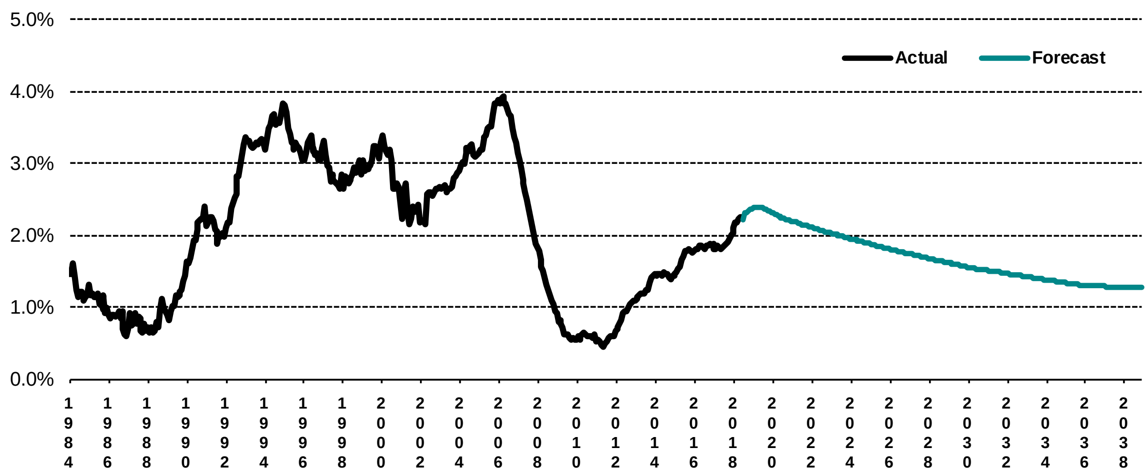

Figure 9. Residential customer growth rates (12-month change)

Final sales to residential retail customers is an equation that considers several factors affecting electricity sales to the residential sector. Residential sales are a function of HDD (wintertime); CDD (summertime); historic energy efficiency trends in Idaho Power's residential customer base; saturation and replacement cycle of appliances; the number of service-area households; the real price of electricity; and the real price of natural gas to name a few. A general schematic of the forecasting methodology used in Idaho Power's residential sales forecast is provided in Figure 10.

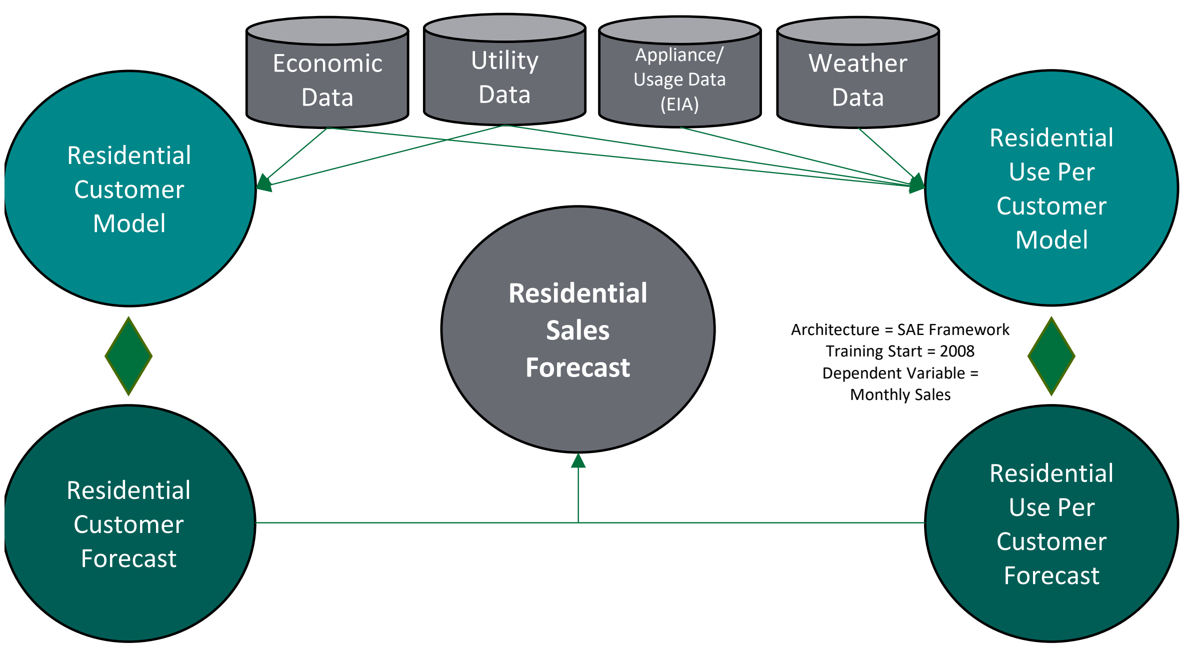

Figure 10. Residential sales forecast methodology framework

COMMERCIAL

The commercial category is primarily made up of Idaho Power's small general-service and large general-service customers. Additional customer types associated with this category include small general-service on-site generation, customer energy production net-metering, unmetered general service, street-lighting service, traffic-control signal lighting service, and dusk-to-dawn customer lighting.

Within the expected-case scenario, the commercial load is projected to increase from 473 aMW in 2019 to 587 aMW in 2038 (Table 8). The average annual compound-growth rate of the commercial load is 1.1 percent during the forecast period. The commercial load in the 70th-percentile scenario is projected to increase from 479 aMW in 2019 to 595 aMW in 2038. The commercial load forecast scenarios are illustrated in Figure 11.

Table 8. Commercial load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	488	512	542	607	1.2%
70th Percentile	479	503	533	595	1.1%
Expected Case	473	496	525	587	1.1%

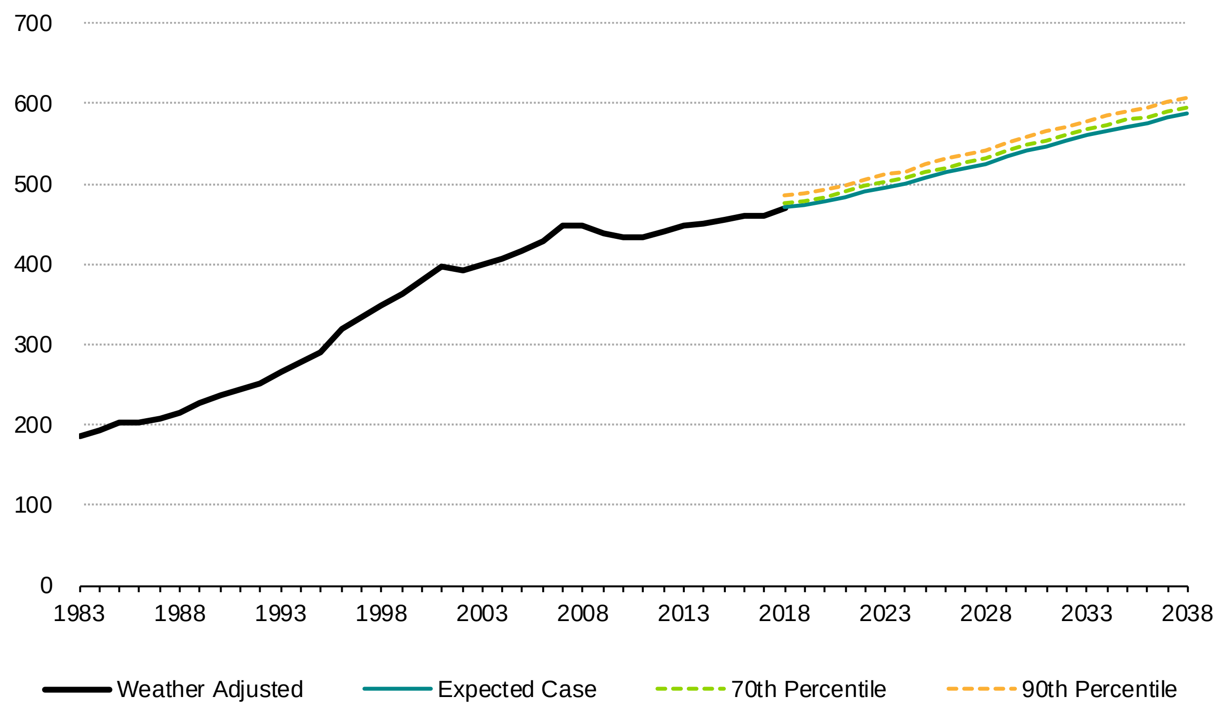

Figure 11. Forecast commercial load (aMW)

With a customer base of nearly 72,000, the commercial class represents the diversity of the service area economy, ranging from residential subdivision pressurized irrigation to large manufacturers. Due to this diversity in load intensity and use, the category is further segmented into categories associated with common elements of energy-use influences, such as economic variables (e.g., employment), industry (e.g., manufacturing), and building structure characteristics (e.g., offices). Figure 12 shows the breakdown of the categories and their relative sizes based on 2018 billed energy sales.

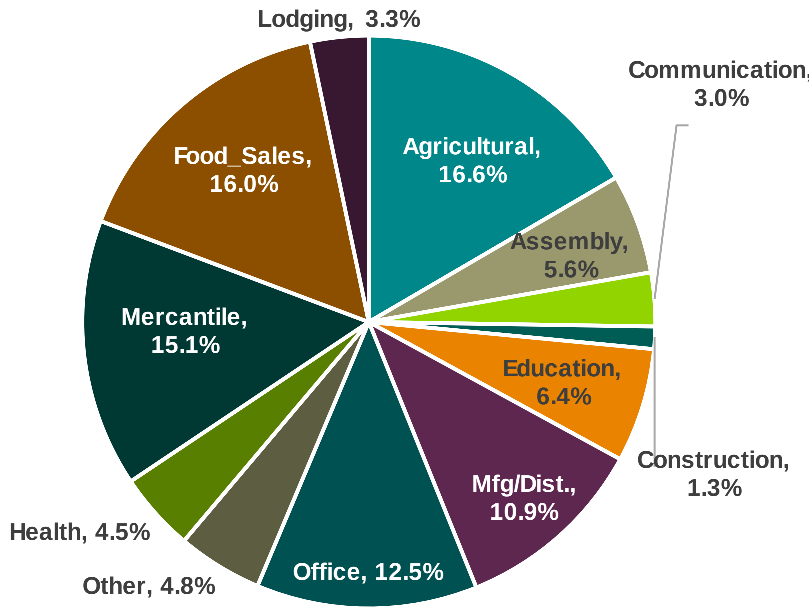

Figure 12. **Commercial building share—energy bills**

As indicated in Figure 12, agricultural-related, food sales, and the retail goods and service providers of the mercantile category represent nearly half of the sector. Recent trends in the sector show that mercantile growth has moderated. This moderation is primarily due to customer consolidation, growth in internet-based sales, energy efficient retrofitting, and new-construction technology implementation (particularly in the area of lighting). Categories showing significant growth over the past five years are reflective of the changing profile of economic and demographic growth in the service territory. Residential growth has led to a construction boom that has seen construction grow by 17 percent, and the residential profile of older customers has helped to push health care growth to 6 percent. Agricultural and manufacturing operations continue to migrate and flourish with growth rates of 9 percent and 6 percent respectively.

The number of commercial customers is expected to increase at an average annual rate of 1.7 percent, reaching approximately 100,000 customers by December 2038.

In 1988, customers in the commercial category consumed approximately 18 percent of Idaho Power system sales, growing to 28 percent by 2018. This share is forecast to remain at the upper end of this range throughout the planning period.

Figure 13 shows historical and forecast average use per customer (UPC) for the entire category. The commercial-use-per-customer metric in Figure 13 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy use per customer, nonetheless it is instructive in aggregate for comparative purposes.

The UPC peaked in 2001 at 67,575 kWh and has declined at approximately 0.9 percent compounded annually to 2018. The UPC is forecast to decrease at an annual rate of 0.5 percent over the planning period. For this category, common elements that drive use down include increases in business-cycle recessions, adoption of energy efficiency technology, and electricity prices.

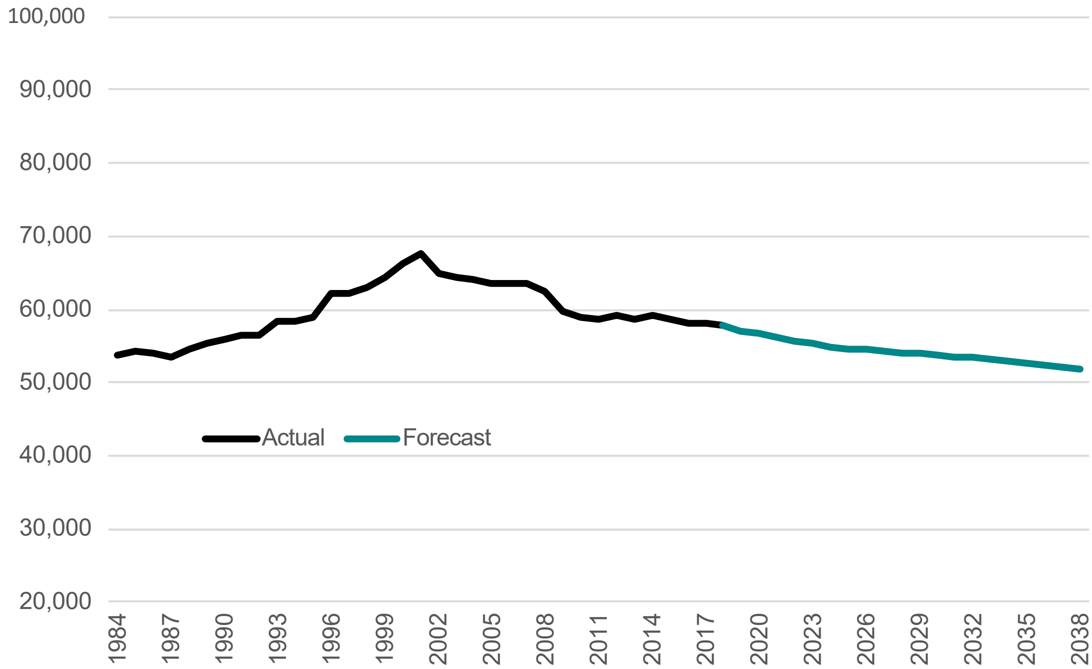

Figure 13. Forecast commercial use per customer (weather-adjusted kWh)

Figure 14 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2018 UPC for each segment relative to the 2011 UPC. A value greater than 100 percent indicates the UPC has risen over the period. The figure supports the general decline of the aggregated trend of Figure 13 but highlights differences in energy and economic dynamics within the heterogeneous commercial category not evident in the residential category.

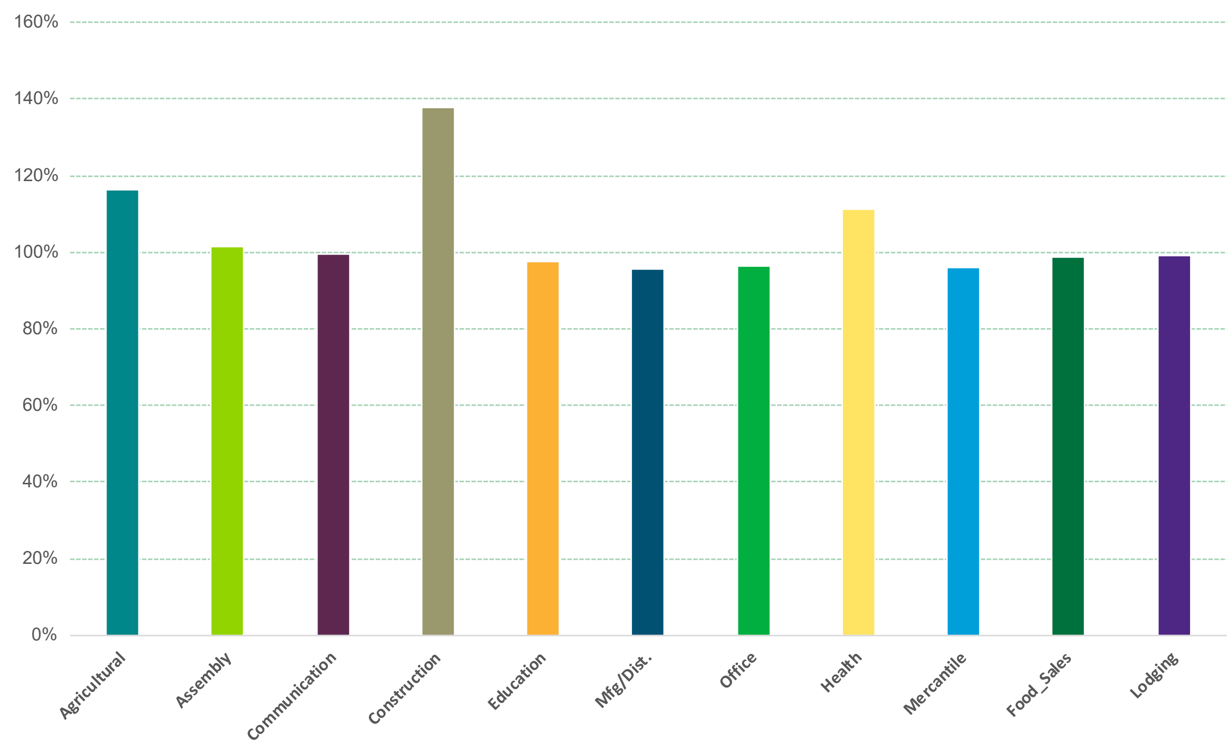

Figure 14. Commercial categories UPC, 2018 relative to 2011

Energy efficiency implementation is a large determinant in UPC decline over time. In the commercial sector, the primary DSM technology impact has come from lighting. The categories of mercantile and office are particularly dominant in this implementation as indicated by the UPC trend. Faster growing categories, such as healthcare tend to show positive UPC trends. Other influences on UPC include differences in price sensitivity, sensitivity to business cycles and weather, and degree and trends in automation. In addition, category UPC can vary when a customer's total use increases to the point where it must, by tariff rules, migrate to an industrial (Rate 19) category. Due to tariff migration, which occurs at the boundary of Schedule 9P (large primary commercial) and Schedule 19 (large industrial), the forecast models aggregate the energy use of these two schedules to ensure continuity in the dependent variable.

The commercial-sales forecast equations consider several varying factors, as informed by the regression models, and vary depending on the category. Typical variables include weather: HDD (wintertime); CDD (summertime); specific industry growth characteristics and outlook; service-area demographics such as households, employment, small business conditions; the real price of electricity; and energy efficiency adoption.

INDUSTRIAL

The industrial category is comprised of Idaho Power's large power service (Schedule 19) customers requiring monthly metered demands between 1,000 kilowatts (kW) and 20,000 kW. The category name "Industrial" is reflective of load requirements and not necessarily indicative of the industrial nature of the customers' business.

In 1980, Idaho Power had about 112 industrial customers, which represented about 12 percent of Idaho Power's system sales. By December 2018, the number of industrial customers had risen to 117, representing approximately 17 percent of system sales. As mentioned earlier in the commercial discussion, customer counts in this tariff class are impacted by migration from and to the commercial class as dictated by the tariff rules. However, generally speaking, customer count growth is primarily illustrative of the positive economic conditions in the service area. Customers with load greater than Schedule 19 ranges are known as special contract customers and are addressed in the Additional Firm Load section of this document.

In the expected-case forecast, industrial load grows from 284 aMW in 2019 to 315 aMW in 2038, an average annual growth rate of 0.6 percent (Table 9). To a large degree, industrial load variability is not associated with weather conditions as is the case with residential, commercial, and irrigation; therefore, the forecasts in the 70^{th}- and 90^{th}-percentile weather scenarios are identical to the expected-case industrial load scenario. The industrial load forecast is pictured in Figure 15.

Table 9. Industrial load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
Expected Case	284	296	305	315	0.6%

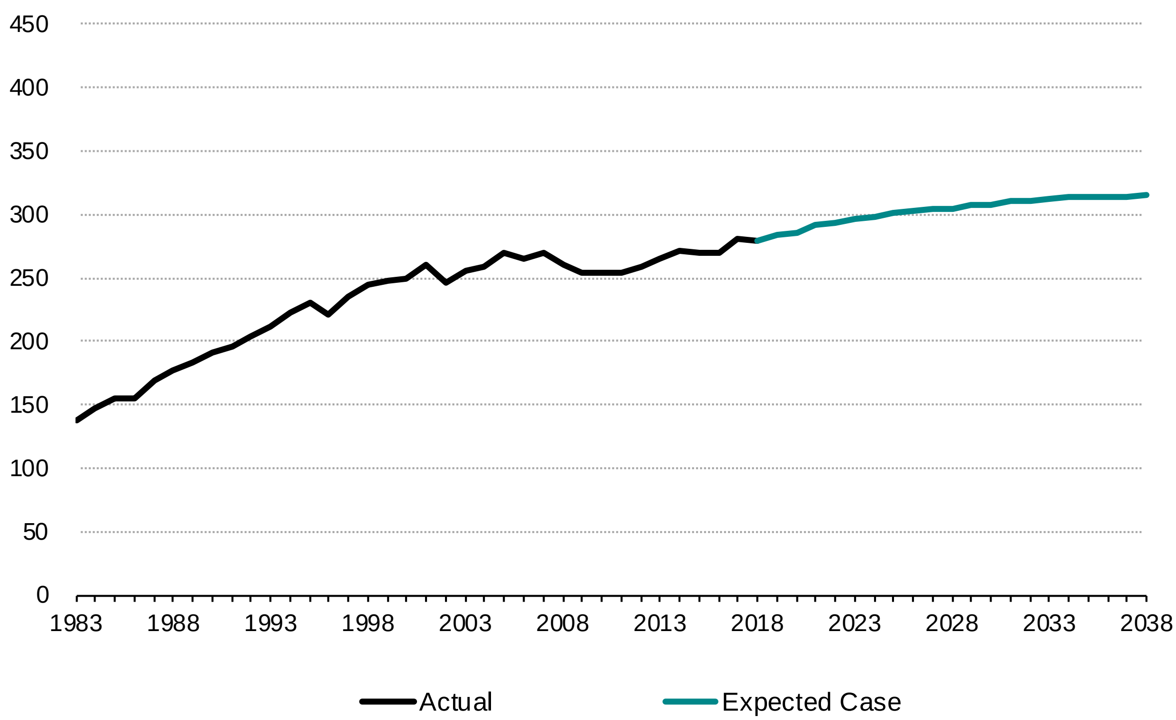

Figure 15. Forecast industrial load (aMW)

As discussed previously the load growth variability is impacted by both economic, non-weather factors, and the impacts of DSM. In developing the forecast, customer-specific DSM implementation is isolated as DSM varies significantly by customer, and the actual energy use is adjusted to remove the impacts of DSM to optimize the causal influence of non-DSM causal variables. The history and forecast of DSM is provided by the DSM specialists within Idaho Power. The economic and other independent variables for the regression models are provided by third-party data providers and internally derived time-series for Idaho Power's service area.

Figure 16 illustrates the 2018 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (38 percent), followed by dairy (18 percent) and construction (7 percent). The categorization scheme includes a range of industrial building types (assembly, lodging, mercantile, warehouse, office, education, and health care). These provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

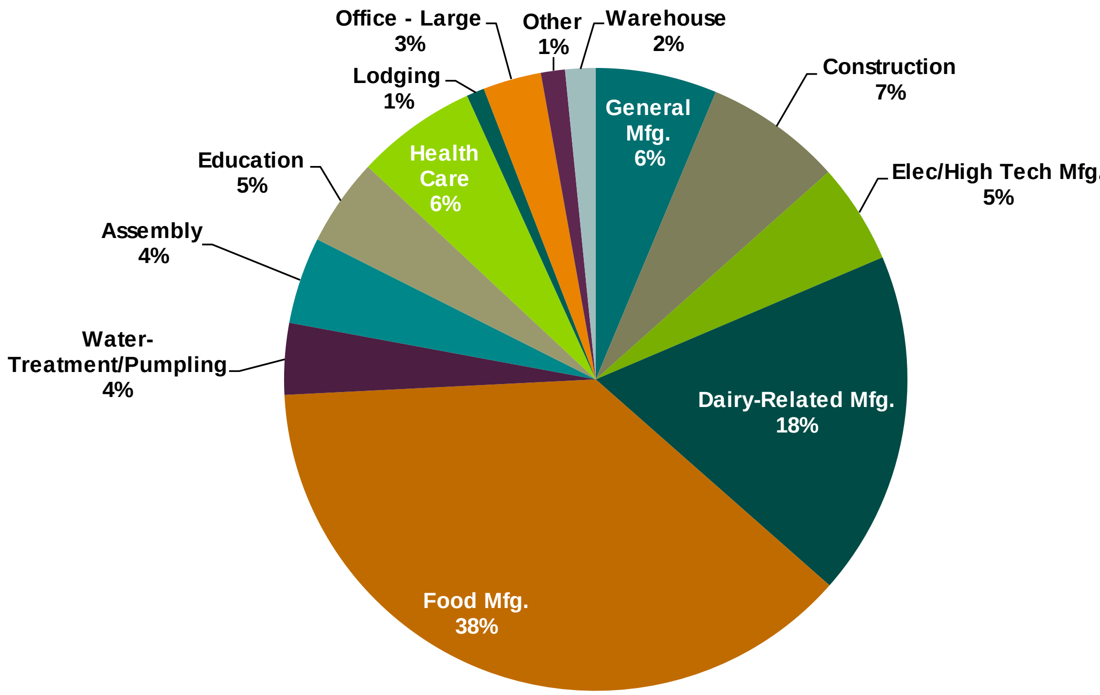

Figure 16. Industrial electricity consumption by industry group (based on 2018 sales)

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and variables such as, economics, price, technological, demographic, and other influences in the form of estimated coefficients from the industry group regression models applied to the appropriate forecasts of independent time series of energy use. From this output, the history and forecast of DSM is subtracted. Figure 17 shows the general forecasting methodology used for both the commercial and industrial sectors.

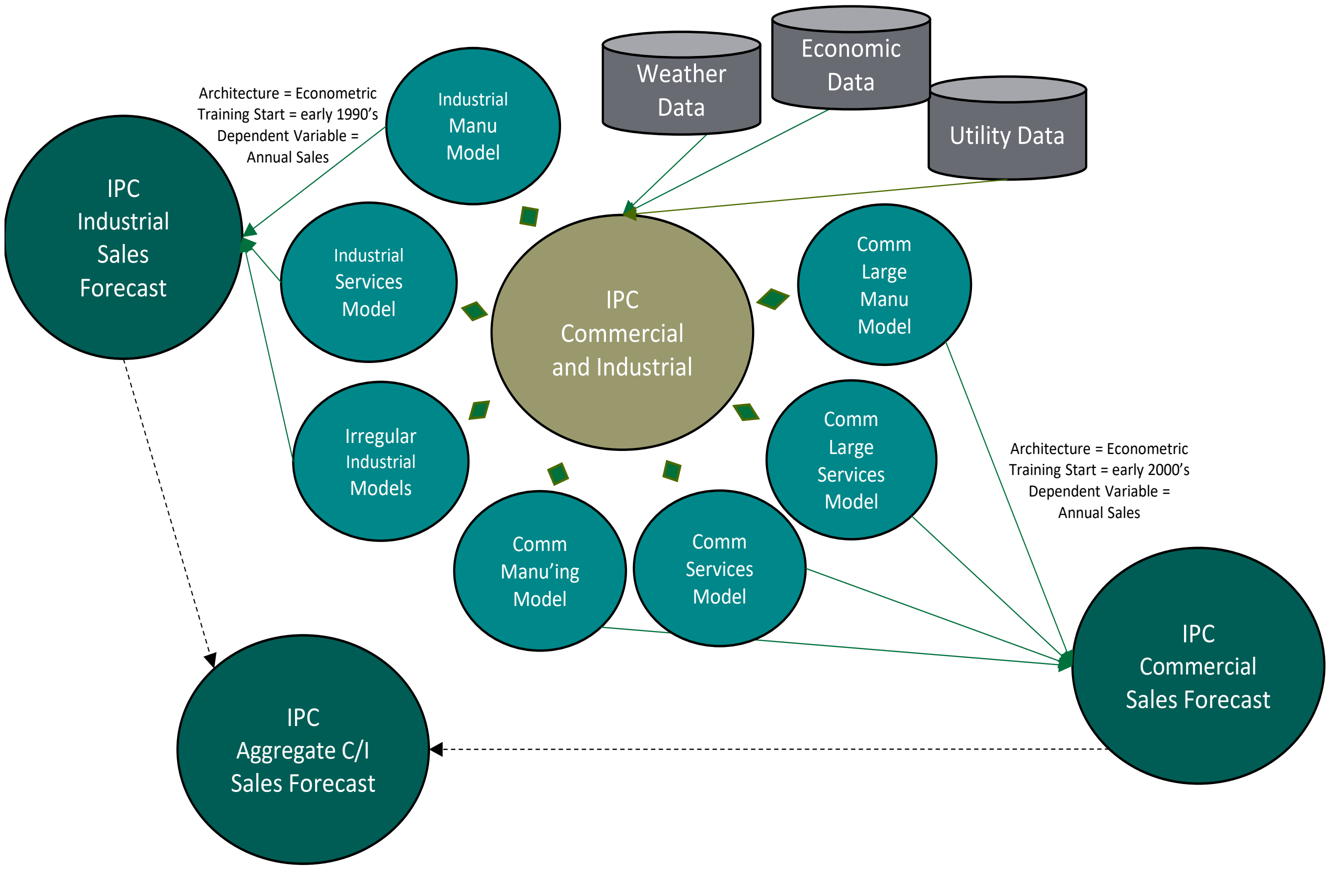

Figure 17. Commercial and industrial general sales forecast methodology

IRRIGATION

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

The expected-case irrigation load is forecast to increase slowly from 222 aMW in 2019 to 258 aMW in 2038, an average annual compound growth rate of 0.8 percent. In the 70th-percentile scenario, irrigation load is projected to be 237 aMW in 2019 and 273 aMW in 2038. The expected-case, 70th-percentile, and 90th-percentile scenarios forecast slower growth than the system in irrigation load from 2019 to 2038. The individual irrigation load forecasts are summarized in Table 10 and illustrated in Figure 18.

Table 10. Irrigation load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
90th Percentile	257	264	273	293	0.7%
70th Percentile	237	244	253	273	0.7%
Expected Case	222	230	238	258	0.8%

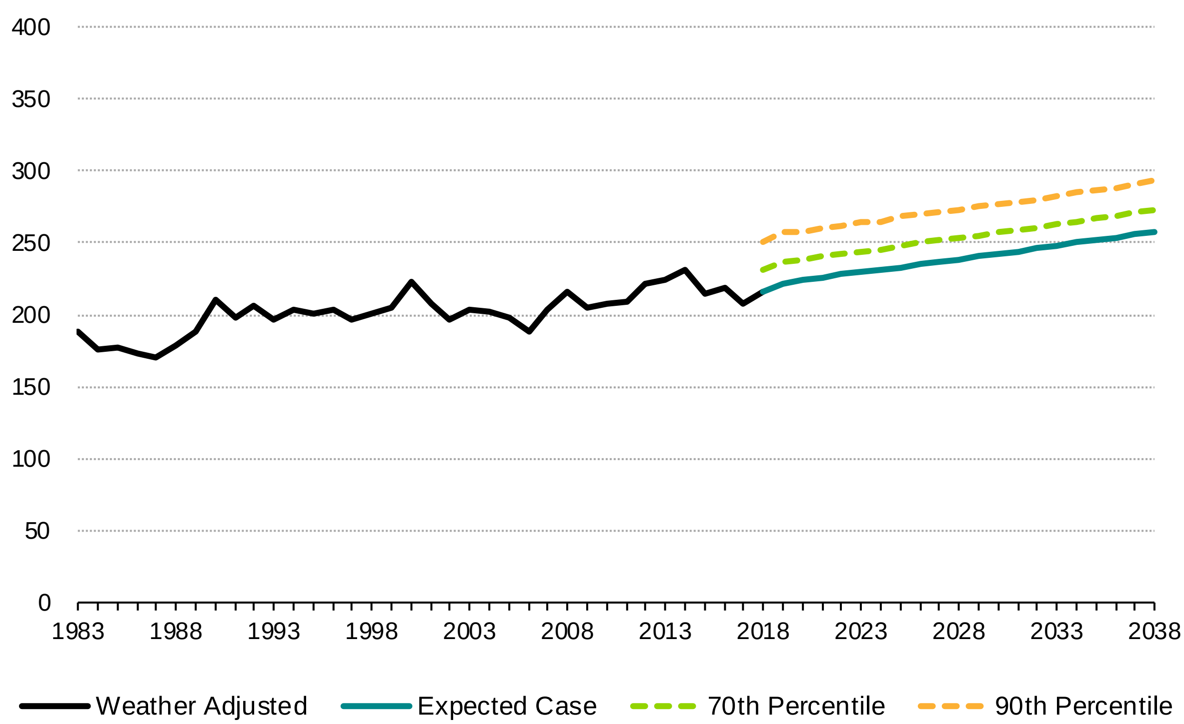

Figure 18. Forecast irrigation load (aMW)

The annual average loads in Table 10 and Figure 18 are calculated using the 8,760 hours in 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 constitute nearly 900 MW. In a normal July, irrigation pumping accounts for roughly 25 percent of the energy consumed during the hour of the annual system peak and nearly 30 percent of the energy consumed during July for general business sales. The forecasted increase of sales is due to the increased customer count from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs. Additionally, the trend toward more water intensive crops, primarily alfalfa and corn, due to growth in the dairy industry, explains most of the increased energy consumption in recent years.

The 2019 irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; spring rainfall; Palmer Z Index (calculated by the National Ocean and Atmospheric Administration [NOAA] from a combination of precipitation, temperature, and soil moisture data); Moody's Producer Price Index: Prices Received by Farmers, All Farm Products; and annual maximum irrigation customer counts.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 megawatt-hours (MWh) to a peak amount of 2,097,000 MWh in 2013. In 1977, irrigation sales reached a maximum proportion of 20 percent of Idaho Power system sales. In 2018, the irrigation proportion of system sales was 13 percent due to the much higher relative growth in other customer classes.

Regarding customer growth, in 1980, Idaho Power had about 10,850 active irrigation accounts. By 2018, the number of active irrigation accounts had increased to 20,459 and is projected to be over 26,000 at the end of the planning period in 2038.

As with other sectors, average use per customer is an important consideration. Since 1988, Idaho Power has experienced growth in the number of irrigation customers but slow growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler irrigated land. The conversion rate is slow and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for sprinkler conversions is drawn from canals and not pumped from deep groundwater wells. In future forecasts, 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.

Additional Firm Load

The additional firm load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate regulatory body. A special contract allows customer-specific, cost-of-service analysis and unique operating characteristics to be accounted for in the agreement.

Individual energy and peak-demand forecasts are developed with for special-contract customers, including Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); and the Idaho National Laboratory (INL). These three special-contract customers comprise the forecast category labeled additional firm load.

In the expected-case forecast, additional firm load is expected to increase from 109 aMW in 2019 to 137 aMW in 2038, an average growth rate of 1.2 percent per year over the planning period (Table 11). 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 19.

Table 11. Additional firm load growth (aMW)

Growth	2019	2023	2028	2038	Annual Growth Rate 2019–2038
Expected Case	109	122	133	137	1.2%

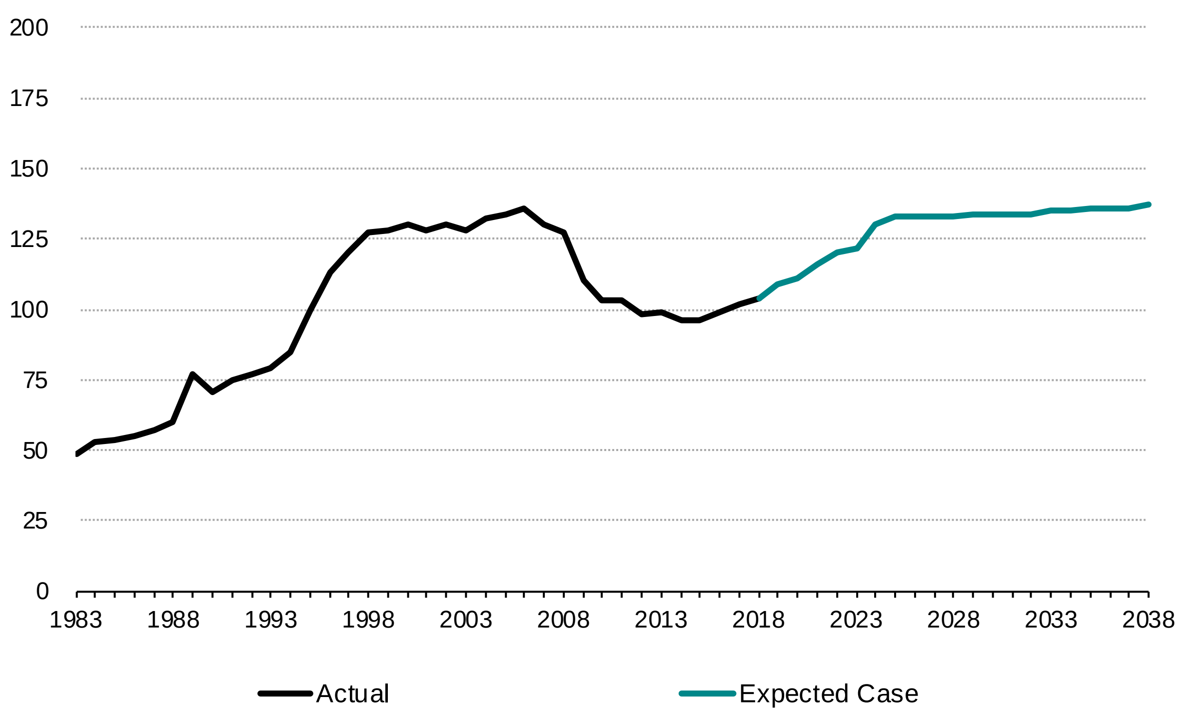

Figure 19. Forecast additional firm load (aMW)

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,900-6,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, and corporate and general services. Micron Technology's electricity use is a function of the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western United States (US). The future electricity usage at the plant is expected to stay flat throughout the twenty-year planning period.

Idaho National Laboratory

INL is part of the US Department of Energy's (DOE) complex of national laboratories. INL is the nation's leading center for nuclear energy research and development. The DOE provided an energy-consumption and peak-demand forecast through 2038 for the INL. The forecast calls for loads to slowly increase through 2023, step up in 2024, then levelize through the remainder of the forecast period.

Additional Considerations

Several influential components and their associated impacts to the sales forecast are treated differently in the forecasting and planning process. The following discussion touches on several of those important topics.

Energy Efficiency

Energy efficiency (EE) influences on past and future load consist of utility programs, statutory codes, and manufacturing standards for appliances, equipment, and building materials that reduce energy consumption. As the influence of statutory codes and manufacturing standards on customers has increased in importance relative to utility programs, Idaho Power continues to modify its forecasting models to fully capture the impact. Idaho Power works closely with its internal Demand Side Management (DSM) program managers and utilizes the updated potential study, most recently developed by Applied Energy Group (AEG). DSM guidance and the achievable potential from AEG are used as a benchmark metric for validating forecast model output.

For residential models, the physical unit flow of energy-efficient products is captured through integrating regional energy efficient product-shipments data into the retail and wholesale distribution channels. The source for the shipments data is the Department of Energy (DOE) and is consistent with DOE's National Energy Model (NEM). This data is first refined by Itron for utility-specific applications. This data captures energy-efficient installations regardless of the source (e.g., programs, standards, and codes).

The DOE/Itron data is recognized in the industry as well-specified for the homogeneous residential sector, however, although DOE data is available for the commercial sector, Idaho Power's test-modeling of the data indicates that the regional data does not provide sufficient segmentation to recognize the heterogeneous differences between the Idaho regional micro-economic composition and the mountain region economy. As discussed in the previous section on forecast methodology within the commercial class, Idaho Power segments the commercial customers by economic and energy profiles and incorporates historical energy efficiency adoption into billed sales. Thus, the energy efficiency is directly modeled into the forecast model energy variable and the forecast is adjusted in conformance with the DSM and AEG potential study forecast to recognize energy efficiency. DOE data is not available for the industrial sector.

The weather and agricultural volatility of the billed sales for the irrigation sector is not well-suited for modeling energy efficiency impacts. Idaho Power monitors energy efficiency implementation in history and forecasts from internal and external sources (DSM staff and presently AEG). The trend of historical implementation (imbedded in the historical usage data) provides a guideline for evaluating the model forecast output relative to expected DSM and codes and standards.

As discussed above, Idaho Power continuously evaluates the models for adequately capturing the impacts of energy efficiency and implements improvements when indicated. With input from

DSM program managers and AEG's knowledge base, Idaho Power retains a high confidence in the representation of the impacts of energy efficiency in the forecast.

A more detailed description of DSM can be found in the main IRP document under the Energy Efficiency Section. Additionally, the company publishes a dedicated DSM annual report submitted to the regulatory agencies.

On-Site Generation

In recent years, the number of customers transitioning to net-metering service (Schedules 6, 8, and 84) has risen dramatically, especially for residential customers. While the current population of on-site generation customers is one-half of one percent of the population of retail customers, recent adoption of solar is relatively strong for our service area.

The installation of generating and storage equipment at customer sites will cause the demand for electricity delivered by Idaho Power to be reshaped throughout the year. It is important to measure the overall and future impact on the sales forecast. Therefore, this year's long-term sales forecast was adjusted downward to reflect the impact of the increase in the number customers with on-site generation, specifically solar, connecting to our system.

Schedules 6, 8, and 84 (net-metering) customer billing histories were compared to billing histories prior to said customer becoming a net-metering customer. The resulting average monthly impact per customer (in kWh) was then multiplied by forecasts of the Schedule 6, 8, and 84 residential and commercial customer counts to estimate the future energy impact on the sales forecast. The forecast of net metering customers serves as a function of historical trends and current policy considerations.

The resulting forecast of net-metering customers multiplied by the estimated use-per-customer sales impact per customer results in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2038, the annual residential sales forecast reduction was about 38 aMW, and the commercial reduction was less than 4 aMW.

Electric Vehicles

The load forecast includes an update of the impact of electric vehicles (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While EV consumer adoption rates in Idaho Power's service area remain relatively low, with continued technological advancement, limiting attributes of vehicle range and refueling time continue to improve the competitiveness of these vehicles to non-electric models.

As the market grows, historical adoption data builds to provide a foundation for forecasting adoption rates and for the models to evolve. IPC receives detailed registration data from Idaho Transportation Department (ITD). The data provides county-level registration which provides a basis for determining IPC service-territory vehicle inventory. However, at present, this data is only available for battery-only vehicles and data for hybrid engine-battery vehicles was not available for this forecast update. Other data sources for monitoring the outlook for PEV adoption includes the U.S. Department of Energy, R.L. Polk, and Moody's Analytics.

Recent registration data shows a strong correlation between vehicles transferred into the service territory and growth of residential in-migration from states with higher PEV share (e.g., California and Washington). IPC subsequently developed a regression model to test the relationship utilizing migration, population and Moody's car registration forecasts. The model results confirm the correlation and the forecast outlook conforms well with the generalized model utilizing DOE data.

The evolution of the PEV market shows that high adoption continues to be evident in warmer climates, high-density and affluent population centers. The IPC forecast for PEVs shows that the service territory will continue to fall into the lower adoption ranges. IPC continues to monitor battery technology advancement, vehicle prices, charging rates and charging station availability which will serve to build the adoption rate in the service territory.

Demand Response

Beginning with the 2009 IRP, the reduction in load associated with demand response programs has been effectively treated as a supply side resource and accounted for in the load and resource balance. Demand response program data, including operational targets for demand reduction, program expenses, and cost-effective summaries are detailed *in Appendix C—Technical Appendix*.

As supply-side resources, demand response program impacts are not incorporated into the sales and load forecast. In the load and resource balance, the forecast 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. However, because energy efficiency programs have an impact on peak demand reduction, a component of peak hour load reduction is integrated into the sales and load forecast models. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in 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 2018 Annual Report*.

Fuel Prices

Fuel prices, in combination with service-area demographic and economic drivers, impact long term trends in electricity sales. Changes in relative fuel prices can also impact the future demand for electricity. Class-level and economic-sector-level regression models were used to identify the relationships between real historical electricity prices and their impact on 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. 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 12. 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 12. Residential fuel-price escalation (2019–2038) (average annual percent change)

	Nominal	Real*
Electricity—2019 IRP	1.3%	-0.6%
Electricity—2017 IRP	1.6%	–0.3%
Natural Gas	2.9%	1.0%

* Adjusted for inflation

Figure 20 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1980 to 2018 and over the forecast period 2019 to 2038. Both nominal and real prices are shown. In the 2019 IRP, nominal electricity prices are expected to climb to about 13 cents per kWh by the end of the forecast period in 2038. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 0.6 percent annually. In the 2017 IRP, nominal electricity prices were assumed to climb to about 13 cents per kWh by 2038, and real electricity prices (inflation adjusted) were expected to decline over the forecast period at an average rate of -0.3 percent annually.

The electricity price forecast used to prepare the sales and load forecast in the 2019 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2017 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2017 IRP sales and load forecast, the 2019 IRP price forecast yielded higher future prices. The retail prices are slightly higher throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.

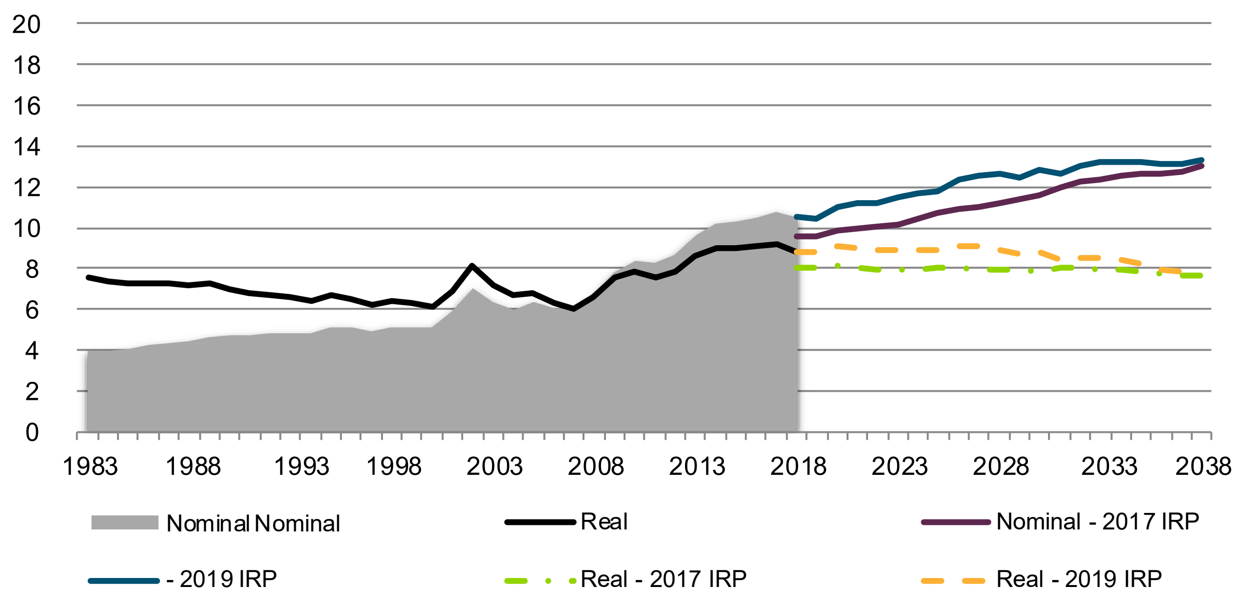

Figure 20. Forecast residential electricity prices (cents per kWh)

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002, a direct result of the western US energy crisis of 2000 and 2001. Prior to 2001, Idaho Power's electricity prices were historically quite stable. From 1990 to 2000, nominal electricity prices rose only 8 percent overall, an annual average compound growth rate of 0.8 percent annually. More recently, over the period 2008 to 2018, nominal electricity prices rose 78 percent overall, an annual average compound growth rate of 4.5 percent annually.

Figure 21 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1983 to 2017 and forecast prices from 2018 to 2038. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. Since spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. Since 2006, natural gas prices have declined about 39 percent, compared to 2017. Nominal natural gas prices are initially expected to drop by 7 percent in 2018, then rise at a steady pace throughout the remainder of the forecast period, increasing 80 percent by 2038, growing at an average rate of 2.9 percent per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 1.0 percent annually.

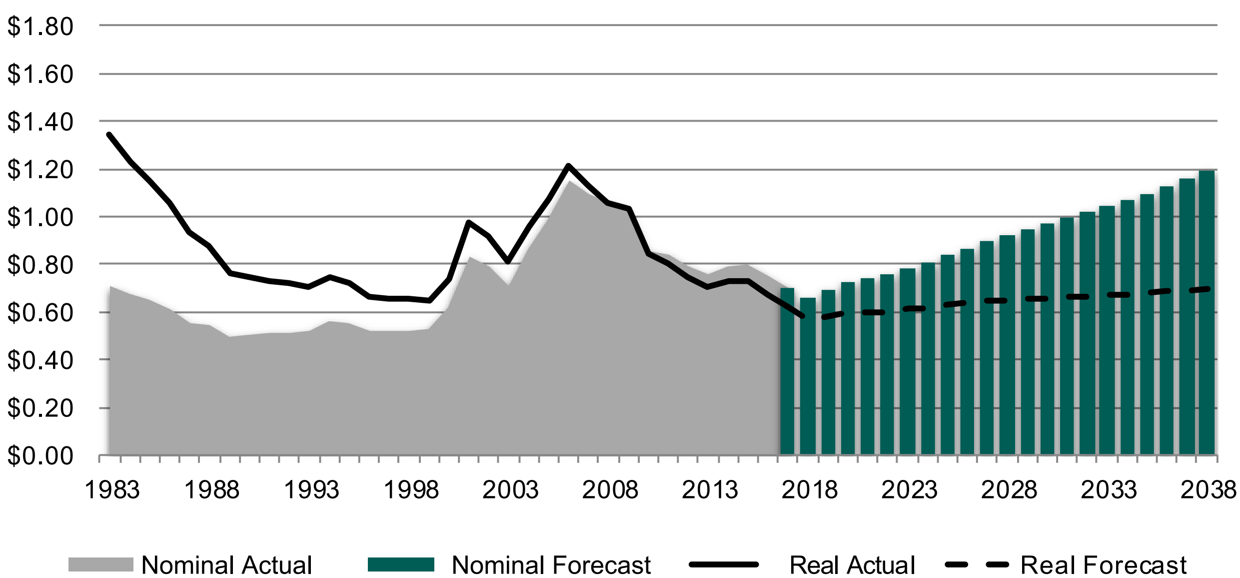

Figure 21. Forecast residential natural gas prices (dollars per therm)

One consideration in determining the operating costs of space heating and water heating is fuel cost, if future natural gas price increases outpace electricity price increases, heating with electricity would become more advantageous when compared to that of natural gas. The US Energy Information Administration (EIA) provides the forecasts of long-term changes in nominal natural gas prices. In the 2019 IRP price forecast, the long-term direction in real electricity prices (adjusted for inflation) is downward and the long-term projection in real natural gas prices is upward, with prices slowly rising throughout the forecast period.

Other Considerations

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

Loss factors are determined by Idaho Power's Transmission Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the revised loss coefficients were lower than those applied to generation forecasts developed prior to the 2015 IRP and were used in the development of the 2019 IRP sales and load forecast. This resulted in a one-time permanent reduction of nearly 20 aMW to the load forecast annually.

Hourly Load Forecast

As a result of stakeholder feedback and comments filed in the 2017 IRP Idaho Power has leveraged several years of advanced metering infrastructure (AMI) data to adopte a new hourly load forecasting methodology to be used in the 2019 IRP. The use of AMI data expanded its footprints at Idaho Power and is utilized to inform an hourly load forecast that conforms with forecast methods mentioned throughout this document.

Historical IRP Methodology

Historically, Idaho Power has utilized metered system generation reads and weather data to build a typical system load factor or hourly system shape based on a previous year, which was then applied to the monthly load forecast for the IRP planning horizon. This methodology produced a consistent system shape throughout the load forecast, but it lacked the significant statistical footing of using individual hourly regressions rooted in AMI.

2019 IRP Methodology

In the time between IRP filings, Idaho Power began exploring potential methodology changes regarding hourly load forecasting relative to what the Company currently had in place. While evaluating potential changes, the Company believes it is prudent to maintain the integrity of the historic long-term forecasting methodologies previously employed by Load Forecasting.

Based on the research, the Company concluded that the new methodology should be formed using a neural network. A neural network utilizes the stability of monthly sales data to calibrate and ground the hourly data via monthly peak regressions. Further, the methodology employs control and flexibility on the neural network while still leaning on its more robust statistical underpinnings.

Enhancements to Hourly Load Forecasting

To begin the process, the Company engaged in consultation with the Itron. Together, Idaho Power and Itron designed the framework to introduce concepts of a neural network model that utilized two non-linear nodes and was hinged on currently accepted load forecasting processes. The result of this methodology brought statistical confidence of hourly load modeling to the Company while still conforming to the stability of the legacy methodology of monthly sales forecasting.

An industry approach to weather responsiveness would be to utilize a linear model based on a heating degree day or cooling degree day level of 65 degrees Fahrenheit (°F) (actual point may differ by local utility weather characteristics). Utilities will also often use splines in regression equations to define the weather function to reflect the change of slope as the average daily temperature moves away from the 65°F mark and there is less weather responsiveness. This methodology works very well by minimizing the potential impact of overfitting. Building on this framework, Idaho Power uses a non-linear approach, wherein the derivative or local slope of a curve is calculated at each instance along the weather responsiveness curve. This responsiveness is captured in the neural network.

The neural network design adopted by Idaho Power outputs a single series of hourly energy with only one hidden layer that contains two nodes (H1 and H2) representing the heating and cooling effects along the sales curve. Each of the H1 and H2 nodes uses a logistic activation function with a linear function applied to the output layer, where impacts of the calendar (weekend, weekday, holidays, etc.) are captured.

A distinct model is developed for each hour of the year to capture the full spectrum of temperature responsiveness. For each non-linear hourly model, an instantaneous derivative value is calculated along the curve to obtain the relationship of energy sales to temperature. A key initiative for Idaho Power when using a neural network framework is controllability of calculations and reducing risk of overfitting of the tails of the distribution. This is achieved by capturing the derivative value and using it in the hourly forecast using 5-degree gradation bins. Further, by releasing the slopes in this fashion, it creates unique weighting schemes by hour and facilitates the construction of lagged weather impact, weekends, and holidays. The result of these hourly models is a transparent set of weather response functions.

At this point, a typical meteorological year is developed using a rolling 30 years of weather history within the Idaho Power service territory. The Company then uses an algorithm to rank and average the daily temperature within a month from hottest to coldest, averaging the daily temperature for each rank across years. The result is an appropriate representation of severe, moderate, and mild daily temperatures for each month. The Company then uses that ranked and averaged typical weather by month and employs a transformation algorithm to reorder days based on a typical weather pattern. Finally, a rotation algorithm is used to ensure that the values over the forecast periods occur on the same day of the week throughout the forecast period, removing the year-to-year variation in the hourly load shape based on where it lands on the calendar of the given forecast year.

Hourly System Load Forecast Design

The output from the neural network is then joined with the abovementioned typical meteorological year (TMY) to develop a near final hourly forecast. An important aspect of the design was for the Company to preserve the monthly sales and monthly peak forecast that has been used historically. The newly developed methodology leverages a more statistically confident approach for allocated sales by hour within the month. To maintain conformance with the historical methodology, the Company applies a calibration algorithm to the hourly forecast to both the monthly peak and energy sales within a month as produced by the legacy linear forms the Company operates. The output of hourly sales and subsequent monthly peaks, as defined from the above-mentioned models, are adjusted such that the duration curve receives minimal adjustment during or around the peak hour, and any required adjustment grows larger as it moves out along the duration curve. This minimizes potential impacts of creating large hour-to-hour swings.

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.

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 additional long-term contracts to supply firm energy to off-system customers if surplus energy is available.

Appendix A1. Historical and Projected Sales and Load

Company System Load (excluding Astaris)
Historical Company System Sales and Load, 1978–2018 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	7,275		901
1979	7,612	4.6%	956
1980	7,880	3.5%	976
1981	8,183	3.9%	1,015
1982	7,865	-3.9%	979
1983	8,038	2.2%	999
1984	8,126	1.1%	1,007
1985	8,279	1.9%	1,028
1986	8,345	0.8%	1,036
1987	8,492	1.8%	1,055
1988	8,822	3.9%	1,093
1989	9,217	4.5%	1,145
1990	9,589	4.0%	1,191
1991	9,753	1.7%	1,210
1992	10,000	2.5%	1,239
1993	10,248	2.5%	1,273
1994	10,670	4.1%	1,325
1995	11,085	3.9%	1,374
1996	11,446	3.3%	1,417
1997	11,769	2.8%	1,460
1998	12,241	4.0%	1,517
1999	12,517	2.3%	1,551
2000	12,942	3.4%	1,603
2001	13,071	1.0%	1,616
2002	12,768	-2.3%	1,584
2003	13,096	2.6%	1,623
2004	13,354	2.0%	1,654
2005	13,652	2.2%	1,696
2006	13,955	2.2%	1,730
2007	14,373	3.0%	1,783
2008	14,467	0.7%	1,786
2009	13,992	-3.3%	1,736
2010	13,841	-1.1%	1,716
2011	13,864	0.2%	1,719
2012	14,061	1.4%	1,738
2013	14,096	0.2%	1,755
2014	14,262	1.2%	1,765
2015	14,102	-1.1%	1,750
2016	14,267	1.2%	1,772
2017	14,380	0.8%	1,778
2018	14,570	1.3%	1,806

Company System Load

Projected Company System Sales and Load, 2019–2038

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	14,788	1.5%	1,833
2020	14,963	1.2%	1,849
2021	15,139	1.2%	1,876
2022	15,329	1.3%	1,899
2023	15,517	1.2%	1,923
2024	15,752	1.5%	1,946
2025	15,923	1.1%	1,972
2026	16,066	0.9%	1,990
2027	16,205	0.9%	2,008
2028	16,362	1.0%	2,022
2029	16,530	1.0%	2,048
2030	16,675	0.9%	2,066
2031	16,820	0.9%	2,084
2032	16,961	0.8%	2,096
2033	17,082	0.7%	2,117
2034	17,224	0.8%	2,134
2035	17,381	0.9%	2,154
2036	17,544	0.9%	2,168
2037	17,702	0.9%	2,194
2038	17,850	0.8%	2,212

Residential Load

Historical Residential Sales and Load, 1978–2018 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	194,650		14,714	2,864		322
1979	202,982	4.3%	13,892	2,820	-1.5%	330
1980	209,629	3.3%	14,846	3,112	10.4%	355
1981	213,579	1.9%	14,805	3,162	1.6%	357
1982	216,696	1.5%	13,653	2,959	-6.4%	339
1983	219,849	1.5%	14,338	3,152	6.5%	359
1984	222,695	1.3%	14,085	3,137	-0.5%	357
1985	225,185	1.1%	13,968	3,145	0.3%	359
1986	227,081	0.8%	14,091	3,200	1.7%	366
1987	228,868	0.8%	14,012	3,207	0.2%	367
1988	230,771	0.8%	14,269	3,293	2.7%	375
1989	233,370	1.1%	14,272	3,331	1.1%	381
1990	238,117	2.0%	14,303	3,406	2.3%	389
1991	243,207	2.1%	14,409	3,504	2.9%	401
1992	249,767	2.7%	14,157	3,536	0.9%	403
1993	258,271	3.4%	14,134	3,651	3.2%	418
1994	267,854	3.7%	14,048	3,763	3.1%	430
1995	277,131	3.5%	14,017	3,885	3.2%	444
1996	286,227	3.3%	13,791	3,947	1.6%	451
1997	294,674	3.0%	13,717	4,042	2.4%	461
1998	303,300	2.9%	13,770	4,176	3.3%	477
1999	312,901	3.2%	13,619	4,261	2.0%	487
2000	322,402	3.0%	13,436	4,332	1.6%	494
2001	331,009	2.7%	13,189	4,366	0.8%	497
2002	339,764	2.6%	12,701	4,315	-1.2%	494
2003	349,219	2.8%	12,779	4,463	3.4%	509
2004	360,462	3.2%	12,744	4,594	2.9%	525
2005	373,602	3.6%	12,729	4,756	3.5%	545
2006	387,707	3.8%	12,967	5,027	5.7%	575
2007	397,286	2.5%	13,002	5,165	2.7%	590
2008	402,520	1.3%	12,890	5,188	0.4%	591
2009	405,144	0.7%	12,758	5,169	-0.4%	589
2010	407,551	0.6%	12,473	5,083	-1.7%	580
2011	409,786	0.5%	12,434	5,095	0.2%	581
2012	413,610	0.9%	12,351	5,109	0.3%	581
2013	418,892	1.3%	12,043	5,045	-1.2%	579
2014	425,036	1.5%	11,939	5,074	0.6%	576
2015	432,275	1.7%	11,643	5,033	-0.8%	575
2016	440,362	1.9%	11,585	5,102	1.4%	582
2017	448,800	1.9%	11,496	5,159	1.1%	588
2018	459,128	2.3%	11,335	5,204	0.9%	594

Projected Residential Sales and Load, 2019–2038

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	470,304	2.4%	11,190	5,263	1.1%	601
2020	481,116	2.3%	11,047	5,315	1.0%	606
2021	491,696	2.2%	10,913	5,366	1.0%	613
2022	502,081	2.1%	10,800	5,422	1.1%	620
2023	512,271	2.0%	10,734	5,499	1.4%	628
2024	522,267	2.0%	10,665	5,570	1.3%	635
2025	532,070	1.9%	10,595	5,637	1.2%	644
2026	541,681	1.8%	10,506	5,691	0.9%	650
2027	551,098	1.7%	10,417	5,741	0.9%	656
2028	560,321	1.7%	10,366	5,808	1.2%	662
2029	569,351	1.6%	10,339	5,886	1.3%	672
2030	578,200	1.6%	10,274	5,940	0.9%	679
2031	586,943	1.5%	10,218	5,998	1.0%	685
2032	595,553	1.5%	10,161	6,052	0.9%	689
2033	604,028	1.4%	10,084	6,091	0.6%	696
2034	612,354	1.4%	10,051	6,155	1.0%	703
2035	620,539	1.3%	10,051	6,237	1.3%	713
2036	628,700	1.3%	10,064	6,327	1.4%	721
2037	636,852	1.3%	10,074	6,415	1.4%	733
2038	645,069	1.3%	10,073	6,498	1.3%	742

Commercial Load

Historical Commercial Sales and Load, 1978–2018 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	27,831		52,510	1,461		169
1979	28,087	0.9%	56,373	1,583	8.3%	180
1980	28,797	2.5%	54,169	1,560	-1.5%	178
1981	29,567	2.7%	54,311	1,606	2.9%	184
1982	30,167	2.0%	54,130	1,633	1.7%	186
1983	30,776	2.0%	52,660	1,621	-0.8%	185
1984	31,554	2.5%	53,626	1,692	4.4%	193
1985	32,418	2.7%	54,254	1,759	3.9%	202
1986	33,208	2.4%	53,980	1,793	1.9%	204
1987	33,975	2.3%	53,546	1,819	1.5%	208
1988	34,723	2.2%	54,467	1,891	4.0%	216
1989	35,638	2.6%	55,468	1,977	4.5%	226
1990	36,785	3.2%	55,909	2,057	4.0%	236
1991	37,922	3.1%	56,341	2,137	3.9%	244
1992	39,022	2.9%	56,578	2,208	3.3%	252
1993	40,047	2.6%	58,289	2,334	5.7%	267
1994	41,629	4.0%	58,445	2,433	4.2%	279
1995	43,165	3.7%	58,787	2,538	4.3%	291
1996	44,995	4.2%	62,134	2,796	10.2%	319
1997	46,819	4.1%	62,230	2,914	4.2%	333
1998	48,404	3.4%	62,894	3,044	4.5%	349
1999	49,430	2.1%	64,283	3,178	4.4%	363
2000	50,117	1.4%	66,151	3,315	4.3%	379
2001	51,501	2.8%	67,575	3,480	5.0%	397
2002	52,915	2.7%	64,864	3,432	-1.4%	392
2003	54,194	2.4%	64,405	3,490	1.7%	399
2004	55,577	2.6%	64,075	3,561	2.0%	406
2005	57,145	2.8%	63,637	3,637	2.1%	416
2006	59,050	3.3%	63,613	3,756	3.3%	429
2007	61,640	4.4%	63,471	3,912	4.2%	447
2008	63,492	3.0%	62,334	3,958	1.2%	449
2009	64,151	1.0%	59,821	3,838	-3.0%	439
2010	64,421	0.4%	58,973	3,799	-1.0%	433
2011	64,921	0.8%	58,596	3,804	0.1%	434
2012	65,599	1.0%	59,059	3,874	1.8%	441
2013	66,357	1.2%	58,753	3,899	0.6%	447
2014	67,113	1.1%	59,067	3,964	1.7%	451
2015	68,000	1.3%	58,639	3,987	0.6%	456
2016	68,883	1.3%	58,178	4,007	0.5%	460
2017	69,850	1.4%	58,014	4,052	1.1%	461
2018	71,104	1.8%	57,884	4,116	1.6%	471

Projected Commercial Sales and Load, 2019–2038

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	72,507	2.0%	57,135	4,143	0.7%	473
2020	74,033	2.1%	56,680	4,196	1.3%	478
2021	75,561	2.1%	56,057	4,236	0.9%	484
2022	77,060	2.0%	55,719	4,294	1.4%	491
2023	78,519	1.9%	55,311	4,343	1.1%	496
2024	79,937	1.8%	54,911	4,389	1.1%	500
2025	81,315	1.7%	54,662	4,445	1.3%	508
2026	82,653	1.6%	54,451	4,501	1.3%	514
2027	83,985	1.6%	54,211	4,553	1.2%	520
2028	85,328	1.6%	54,030	4,610	1.3%	525
2029	86,686	1.6%	53,877	4,670	1.3%	534
2030	88,060	1.6%	53,754	4,734	1.4%	541
2031	89,447	1.6%	53,552	4,790	1.2%	547
2032	90,846	1.6%	53,401	4,851	1.3%	553
2033	92,256	1.6%	53,152	4,904	1.1%	560
2034	93,674	1.5%	52,885	4,954	1.0%	566
2035	95,097	1.5%	52,615	5,004	1.0%	572
2036	96,522	1.5%	52,331	5,051	0.9%	575
2037	97,946	1.5%	52,047	5,098	0.9%	582
2038	99,367	1.5%	51,706	5,138	0.8%	587

Irrigation Load

Historical Irrigation Sales and Load, 1978–2018 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	10,476		154,696	1,621		185
1979	10,711	2.2%	163,250	1,749	7.9%	199
1980	10,854	1.3%	160,522	1,742	-0.4%	198
1981	11,248	3.6%	168,088	1,891	8.5%	216
1982	11,312	0.6%	154,149	1,744	-7.8%	199
1983	11,133	-1.6%	147,935	1,647	-5.5%	188
1984	11,375	2.2%	136,138	1,549	-6.0%	176
1985	11,576	1.8%	133,571	1,546	-0.2%	177
1986	11,308	-2.3%	133,880	1,514	-2.1%	173
1987	11,254	-0.5%	132,363	1,490	-1.6%	170
1988	11,378	1.1%	137,228	1,561	4.8%	178
1989	11,957	5.1%	137,547	1,645	5.3%	188
1990	12,340	3.2%	149,104	1,840	11.9%	210
1991	12,484	1.2%	138,808	1,733	-5.8%	198
1992	12,809	2.6%	140,990	1,806	4.2%	206
1993	13,078	2.1%	131,515	1,720	-4.8%	196
1994	13,559	3.7%	131,687	1,786	3.8%	204
1995	13,679	0.9%	128,970	1,764	-1.2%	201
1996	14,074	2.9%	126,538	1,781	0.9%	203
1997	14,383	2.2%	119,833	1,724	-3.2%	197
1998	14,695	2.2%	119,957	1,763	2.3%	201
1999	14,912	1.5%	120,501	1,797	1.9%	205
2000	15,253	2.3%	128,579	1,961	9.1%	223
2001	15,522	1.8%	117,148	1,818	-7.3%	208
2002	15,840	2.0%	108,904	1,725	-5.1%	197
2003	16,020	1.1%	111,637	1,788	3.7%	204
2004	16,297	1.7%	108,844	1,774	-0.8%	202
2005	16,936	3.9%	102,342	1,733	-2.3%	198
2006	17,062	0.7%	97,182	1,658	-4.3%	189
2007	17,001	-0.4%	105,177	1,788	7.8%	204
2008	17,428	2.5%	108,923	1,898	6.2%	216
2009	17,708	1.6%	101,440	1,796	-5.4%	205
2010	17,846	0.8%	102,016	1,821	1.4%	208
2011	18,292	2.5%	99,972	1,829	0.4%	209
2012	18,675	2.1%	104,167	1,945	6.4%	221
2013	19,017	1.8%	103,711	1,972	1.4%	225
2014	19,328	1.6%	104,486	2,020	2.4%	231
2015	19,756	2.2%	95,158	1,880	-6.9%	215
2016	20,042	1.4%	96,149	1,927	2.5%	219
2017	20,246	1.0%	89,806	1,818	-5.6%	208
2018	20,459	1.1%	92,543	1,893	4.1%	216

Projected Irrigation Sales and Load, 2019–2038

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	20,727	1.3%	93,816	1,945	2.7%	222
2020	21,010	1.4%	93,458	1,964	1.0%	224
2021	21,290	1.3%	92,870	1,977	0.7%	226
2022	21,570	1.3%	92,453	1,994	0.9%	228
2023	21,852	1.3%	92,026	2,011	0.8%	230
2024	22,134	1.3%	91,565	2,027	0.8%	231
2025	22,413	1.3%	91,103	2,042	0.7%	233
2026	22,694	1.3%	90,684	2,058	0.8%	235
2027	22,975	1.2%	90,304	2,075	0.8%	237
2028	23,253	1.2%	89,943	2,091	0.8%	238
2029	23,537	1.2%	89,558	2,108	0.8%	241
2030	23,817	1.2%	89,198	2,124	0.8%	243
2031	24,096	1.2%	88,845	2,141	0.8%	244
2032	24,380	1.2%	88,474	2,157	0.8%	246
2033	24,658	1.1%	88,141	2,173	0.8%	248
2034	24,941	1.1%	87,815	2,190	0.8%	250
2035	25,219	1.1%	87,514	2,207	0.8%	252
2036	25,502	1.1%	87,223	2,224	0.8%	253
2037	25,781	1.1%	86,961	2,242	0.8%	256
2038	26,064	1.1%	86,694	2,260	0.8%	258

Industrial Load

Historical Industrial Sales and Load, 1978–2018 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	99		9,786,753	972		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%	19,412,391	2,308	-2.4%	261
2009	124	4.0%	17,987,570	2,224	-3.6%	254
2010	121	-2.0%	18,404,875	2,232	0.3%	254
2011	120	-1.1%	18,597,050	2,230	-0.1%	254
2012	115	-4.2%	19,757,921	2,271	1.8%	258
2013	114	-0.7%	20,281,837	2,314	1.9%	265
2014	113	-0.7%	20,863,653	2,363	2.1%	271
2015	116	2.8%	20,271,082	2,360	-0.1%	269
2016	118	1.4%	19,993,955	2,361	0.0%	270
2017	117	-1.1%	20,996,425	2,453	3.9%	280
2018	115	-1.6%	21,272,694	2,446	-0.3%	279

Projected Industrial Sales and Load, 2019–2038

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	113	-1.7%	21,962,765	2,482	1.4%	284
2020	113	0.0%	22,221,031	2,511	1.2%	286
2021	115	1.8%	22,152,471	2,548	1.5%	291
2022	115	0.0%	22,350,111	2,570	0.9%	294
2023	115	0.0%	22,567,691	2,595	1.0%	296
2024	116	0.9%	22,582,643	2,620	0.9%	298
2025	116	0.0%	22,745,374	2,638	0.7%	301
2026	118	1.7%	22,479,895	2,653	0.5%	303
2027	118	0.0%	22,620,402	2,669	0.6%	305
2028	118	0.0%	22,722,807	2,681	0.5%	305
2029	118	0.0%	22,815,226	2,692	0.4%	307
2030	119	0.8%	22,697,036	2,701	0.3%	308
2031	121	1.7%	22,425,128	2,713	0.5%	310
2032	121	0.0%	22,487,311	2,721	0.3%	310
2033	121	0.0%	22,574,212	2,731	0.4%	312
2034	121	0.0%	22,636,506	2,739	0.3%	313
2035	123	1.7%	22,319,757	2,745	0.2%	313
2036	123	0.0%	22,360,334	2,750	0.2%	313
2037	124	0.8%	22,210,418	2,754	0.1%	314
2038	124	0.0%	22,243,637	2,758	0.1%	315

Additional Firm Sales and Load
Historical Additional Firm Sales and Load, 1978–2018

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1978	357		41
1979	373	4.4%	43
1980	360	-3.5%	41
1981	376	4.6%	43
1982	368	-2.4%	42
1983	425	15.6%	49
1984	466	9.7%	53
1985	471	1.1%	54
1986	482	2.3%	55
1987	502	4.2%	57
1988	530	5.6%	60
1989	671	26.5%	77
1990	625	-6.9%	71
1991	661	5.8%	75
1992	680	2.9%	77
1993	689	1.3%	79
1994	741	7.5%	85
1995	878	18.6%	100
1996	989	12.6%	113
1997	1,048	6.0%	120
1998	1,113	6.2%	127
1999	1,122	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	1,156	3.3%	132
2005	1,175	1.6%	134
2006	1,189	1.2%	136
2007	1,141	-4.0%	130
2008	1,114	-2.4%	127
2009	965	-13.4%	110
2010	907	-6.0%	103
2011	906	0.0%	103
2012	862	-4.8%	98
2013	867	0.5%	99
2014	841	-2.9%	96
2015	842	0.1%	96
2016	870	3.3%	99
2017	897	3.1%	102
2018	910	1.4%	104

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

Projected Additional Firm Sales and Load, 2019–2038

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2019	957	5.1%	109
2020	977	2.1%	111
2021	1,013	3.7%	116
2022	1,048	3.5%	120
2023	1,069	2.0%	122
2024	1,146	7.2%	130
2025	1,161	1.3%	133
2026	1,164	0.3%	133
2027	1,167	0.3%	133
2028	1,171	0.3%	133
2029	1,173	0.2%	134
2030	1,176	0.3%	134
2031	1,178	0.2%	134
2032	1,180	0.2%	134
2033	1,183	0.3%	135
2034	1,186	0.3%	135
2035	1,188	0.2%	136
2036	1,191	0.3%	136
2037	1,193	0.2%	136
2038	1,196	0.3%	137

*Includes Micron Technology, Simplot Fertilizer, and the INL