



IRP

INTEGRATED RESOURCE PLAN

2025

APPENDIX A: Sales and Load Forecast

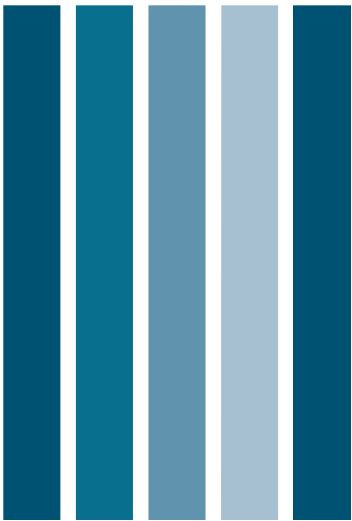


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INTRODUCTION

Appendix A—Sales and Load Forecast includes details on the energy sales and load forecast of future demand for electricity within the company's service area. The forecast covers a 20-year period from 2026 through 2045.

This appendix describes the development of both the monthly sales forecast and peak demand requirement, contains Idaho Power's estimate of sales growth during the 20-year planning period, and presents additional forecast cases prepared to test ranges of forecast variability.

Economic data in the forecast models is primarily sourced from Moody's Analytics and Woods & Poole Economics. The national, state, Metropolitan Statistical Area (MSA), and county economic and demographic projections from these sources are tailored to Idaho Power's service area for the forecast models. Specific demographic projections are also developed for the service area from national and local census data. Additional data sources used to substantiate economic data include, but are not limited to, the Idaho Department of Labor, Construction Monitor (building permits), and Federal Reserve economic databases.

As economic growth assumptions influence several classes of service growth rates, it is important to review key components. Incomes, employment, economic output, and real retail electricity prices are examples of independent variables analyzed to develop load projections. A key demographic component is population or household growth within the company's service area. The number of households in the state of Idaho is projected to grow at an annual rate of 1.7% 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 also projected to grow faster than the state of Idaho at an annual rate of 2.4% during the forecast period. The Boise–Nampa MSA (or the Treasure Valley) is an area encompassing all, or a portion of, Ada, Boise, Canyon, Gem, and Owyhee counties in southwestern Idaho.

Scenarios of weather-related influence on potential ranges of the load forecast are tested utilizing a distribution of normal weather conditions (temperature and precipitation) applied to the weather assumptions in the forecast. This provides a comparative range of outcomes that isolate long-term sustained weather influences on the forecast.

The 50th-percentile load forecast shows Idaho Power's system load increasing to 3,260 average megawatts (aMW) by 2045 from 2,102 aMW in 2026, representing an average yearly growth rate of 2.3% over the 20-year planning period (2026–2045). A similar annual average growth rate in system load is reflected in various weather-related scenarios. From an annual peak-hour demand perspective, the 50th-percentile peak-demand forecast will grow to 5,517 megawatts (MW) in 2045 from the all-time system peak of 3,793 MW that occurred on Monday, July 22,

2024, at 7 p.m. Idaho Power’s system peak is projected to increase at an average growth rate of 1.8% per year over the 20-year planning period (2026–2045). Over this same term, the number of Idaho Power active retail customers is expected to increase from the December 2024 level of 647,793 customers to over 867,000 customers by year-end 2045.

Beyond the weather, climate, economic, and demographic assumptions used to drive the load forecast, several additional assumptions were incorporated into the forecasts of the residential, commercial, industrial, and irrigation sectors. Further discussion about these assumptions is presented in each respective section.

Conservation influences on the load forecast, including Idaho Power identified economic achievable energy efficiency demand-side management (DSM) programs, are included in the load forecast. Idaho Power energy efficiency programs are described in detail in Idaho Power’s *Demand-Side Management 2024 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 area and includes the impact of their energy reduction or addition in the long-term sales and load forecast.

Outside of weather, potential primary 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. Additionally, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity.

Data describing the historical and projected figures for the sales and load forecast are presented in Appendix A1 of this report. Appendix A2 of this report provides forecast model equations and coefficients.

2025 IRP SALES AND LOAD FORECAST

Average Load

The economic and demographic variables driving the 2025 IRP sales and load forecast result in increased annual sales levels throughout the planning period. After the Great Recession in 2008, the extended business cycle recovery process for the national and service area economy muted load growth through 2011. However, in 2012, a recovery process was evident, and on balance stronger growth was exhibited in most economic drivers relative to post Great Recession history. The global pandemic recession in 2020 had profound effects across the national and global economy. For the company, residential use per customer increased approximately 5% in 2020 and into 2021. However, commercial and industrial customers saw a somewhat offsetting decrease during this period. The dramatic change in electricity use per customer that was initially exhibited has since stabilized. There was also a significant increase in population growth during this period as both work-from-home edicts and continued strong in-migration trends were at play. Migration trends have also slowed relative to previous years; however, Idaho has been a top-ten growth state during this time. In fact, Idaho had the highest average annual population growth 2009–2024 relative to all other states in the U.S. Overall, it is assumed economic conditions will continue to carry Idaho as a top economic performer and return to long-term fundamentals during the 2025 IRP forecast term. Additional significant factors and considerations that influence the 2025 IRP load forecast include the following:

- Weather plays a primary role in impacting the load forecast on a monthly and seasonal basis. Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period or defined as normal climatology. Variations of weather percentiles as determined by historic weather are also analyzed.
- The economic forecast used for the 2025 IRP reflects a continued expansionary economy in Idaho over the near term and reversion to the long-term trend of the service area economy. Net migration and business investment continue to result in positive economic activity.
- 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 (UPC) over the forecast period.
- New industrial and Energy Service Agreement (ESA) customer requests are inherently uncertain regarding location and capacity needs. The load forecast only reflects those customers that have made a sufficient and significant binding investment and/or interest indicating a commitment of the highest probability of locating within the service area. The large numbers of prospective businesses that have indicated some interest in

locating in Idaho Power’s service area but have not made sufficient commitments are not included in the sales and load forecast.

- The electricity price forecast used to prepare the sales and load forecast in the 2025 IRP reflects the 2023 IRP preferred portfolio.

Peak-Hour Demands

Average loads are an integral component in determining the peak-hour demands on the system. 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 weather. Like the sales forecast, the peak models incorporate several peak forecast scenarios based on historical probabilities of peak day temperatures for each month of the year. More discussion is provided in the forthcoming sections.

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 ESA customers. The forecast 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. In conjunction with this load (or sales) forecast, an hourly peak-load (peak) forecast was prepared. Figure 1 depicts a summary of the load forecast modeling process.

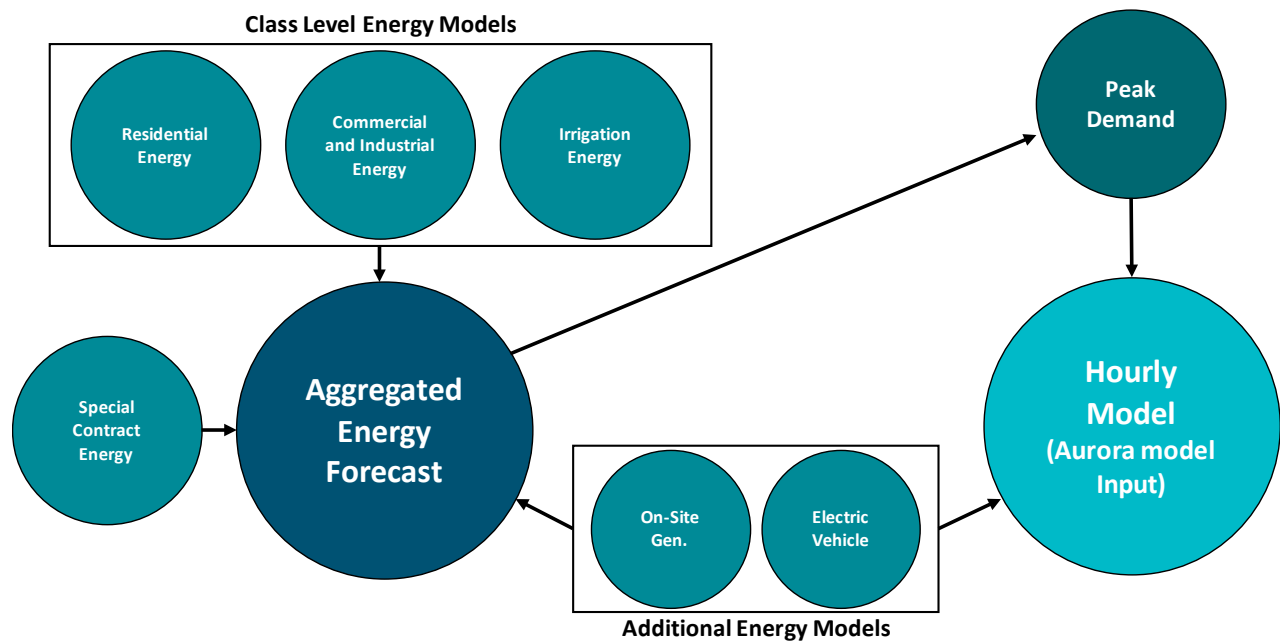


Figure 1. Load forecast modeling process

In addition, several percentile cases were developed for the energy and peak forecasts based on weather variability. Assumptions for each of the individual categories, the peak hour impacts, and forecast methodologies are described throughout this document.

Forecast Percentiles

The future demand for electricity in Idaho Power’s service area is represented by load forecasts reflecting a range of load uncertainty due to weather variability. The 50th-percentile average load forecast assumes average temperatures and precipitation (i.e., there are equal chances loads will be higher or lower than the load forecast due to colder-than-normal or hotter-than-normal temperatures and wetter-than-normal or drier-than-normal precipitation). Since actual loads can vary significantly depending on weather conditions, weather percentile cases were developed to address load variability due to weather.

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 degree days (CDD) and growing degree days (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. For example, the 70th-percentile residential and commercial load forecast temperatures for each month were assumed to be at the 70th-percentile of HDD occurrence in wintertime and at the 70th -percentile of CDD occurrence 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. Results of Idaho Power’s weather-related probabilistic system load projections are reported in the following section.

Additional Scenarios Developed

There have been numerous requests to Idaho Power for development of large commercial and industrial projects over the course of 2024 and 2025. Additional scenarios were developed to capture the potential of these projects moving forward and assess resource adequacy and cost. The first scenario represents a single or aggregate 300 MW ramping on to Idaho Power’s system over the course of the years 2029–2033. The second scenario represents a single or aggregate 500 MW added on to Idaho Power’s system, ramping up over the years 2029–2034.

COMPANY SYSTEM LOAD

System load, or total electricity requirements, is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as ESA customers and on-system contracts (including past sales to Raft River and the City of Weiser). Currently, there are no contracts in effect to provide long-term, firm energy off-system.

The system load forecast is based on the output of the regression and forecasting models referenced previously and represents Idaho Power’s energy sales growth during the planning period. The energy sales growth of the system forecast averages 2.3% per year from 2026 to 2045. These projections are reported in Table 1 and shown in Figure 2.

Table 1. System load growth (aMW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026-2045
95 th Percentile	2,243	2,954	3,255	3,426	2.3%
50 th Percentile	2,102	2,807	3,099	3,260	2.3%
10 th Percentile	1,983	2,683	2,971	3,124	2.4%

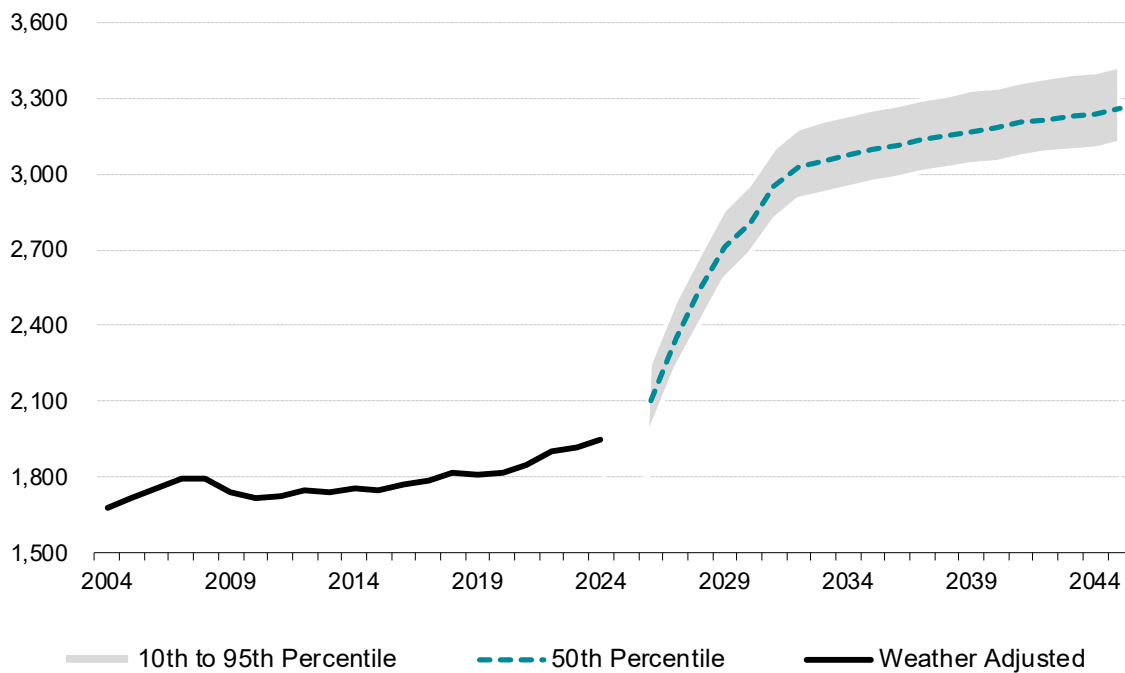


Figure 2. Forecast system load (aMW)

The composition of system company electricity sales by year is shown in Figure 3. Residential sales are forecast to be about 13% higher in 2045, gaining 0.8 million megawatt hours (MWh) over 2026. Commercial sales are expected to be 23% higher, or 1.2 million MWh, followed by

industrial (15% higher, or 0.4 million additional MWh) and irrigation (11% higher in 2045 than 2026). Additional firm sales are expected to more than triple by 2045, gaining 7.1 million MWh over 2026.

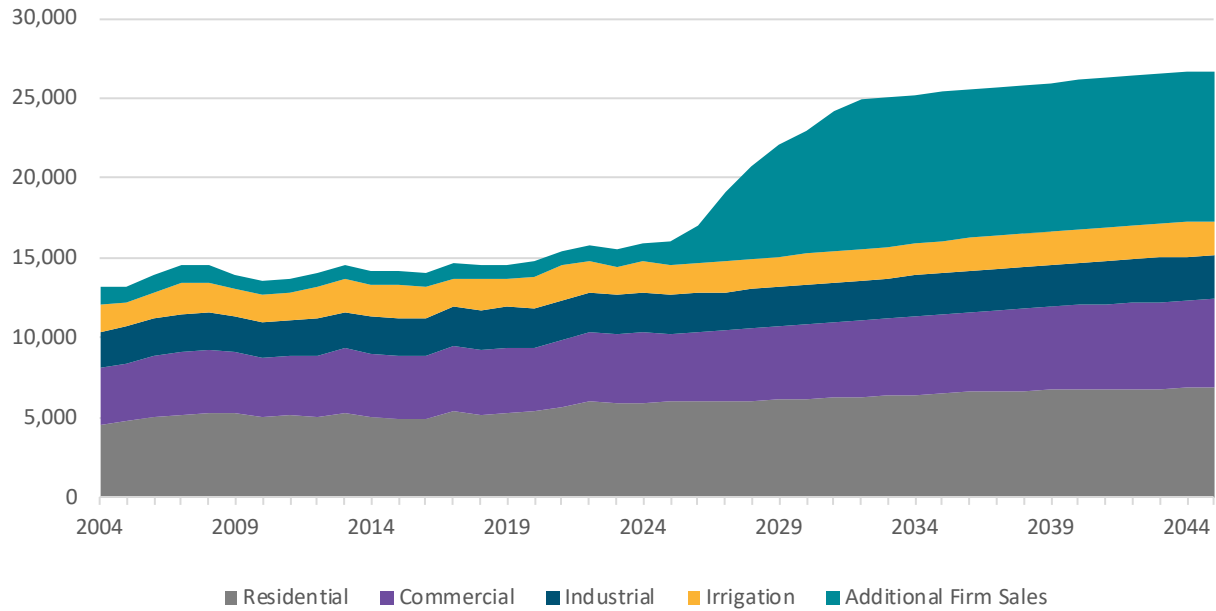


Figure 3. Composition of system company electricity sales (thousands of MWh)

COMPANY SYSTEM PEAK

The system peak forecast includes the sum of the system coincident peak-hour demands of residential, commercial, industrial, and irrigation customers, as well as ESA customers and on-system contracts (Raft River and the City of Weiser, historically). Currently, there are no contracts in effect to provide long-term, firm energy off-system.

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, adjusted for demand response, was 3,827 MW, recorded on Wednesday, July 10, 2024, at 7 p.m. The previous all-time system summer peak demand was 3,751 MW, recorded on Wednesday, June 30, 2021, at 7 p.m. The system summer peak load growth has accelerated in previous decades as a record number of residential, commercial, and industrial customers were added to the system and air conditioning became standard in nearly all new residential homes and commercial buildings.

Note the 2025 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 without the interference of load intervention on causal variables. Projected system summer peak load growth is reported in Table 2 and illustrated in Figure 4. Much of the variation in peak load is due to weather conditions.

Table 2. System summer peak load growth (MW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026-2045
95 th Percentile	4,040	4,878	5,268	5,623	1.8%
50 th Percentile	3,934	4,772	5,162	5,517	1.8%
10 th Percentile	3,845	4,682	5,073	5,428	1.8%

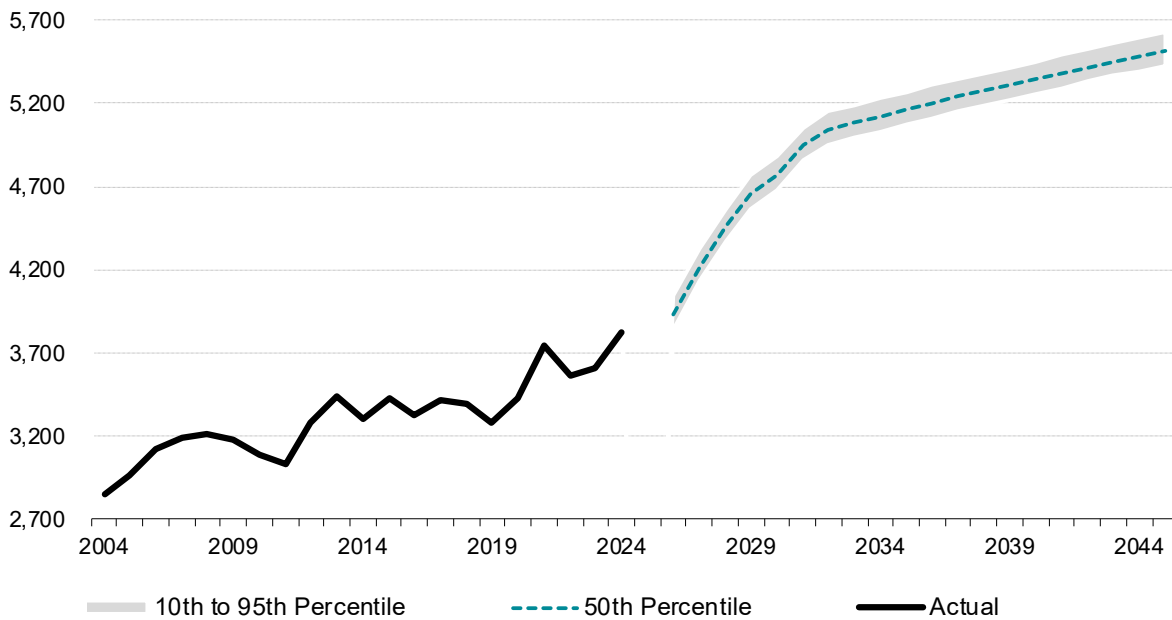


Figure 4. Forecast system summer peak (MW)

The all-time system winter peak demand was 2,719 MW, recorded Tuesday, January 16, 2024, at 9 a.m. The previous all-time system winter peak demand was 2,604 MW, recorded Thursday, December 22, 2022, at 9 a.m. Projected system winter peak load growth is reported in Table 3 and illustrated in Figure 5¹. As shown in Figure 5, the historical system winter peak load is much more variable than the summer system peak load. This is due to the higher variability of peak temperatures in winter months compared to the variability of peak temperatures in summer months. The wider spread of the winter peak forecast lines shown in Figure 5 illustrate the higher variability associated with winter peak temperatures.

Table 3. System winter peak load growth (MW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026–2045
95 th Percentile	3,017	3,723	3,956	4,022	1.5%
50 th Percentile	2,760	3,465	3,699	3,764	1.6%
10 th Percentile	2,557	3,263	3,496	3,562	1.8%

¹ Idaho Power uses a median peak-day temperature driver in lieu of an average peak-day temperature driver in the 50th percentile peak-demand forecast scenario. The median peak-day temperature has a 50% 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 percentiles.

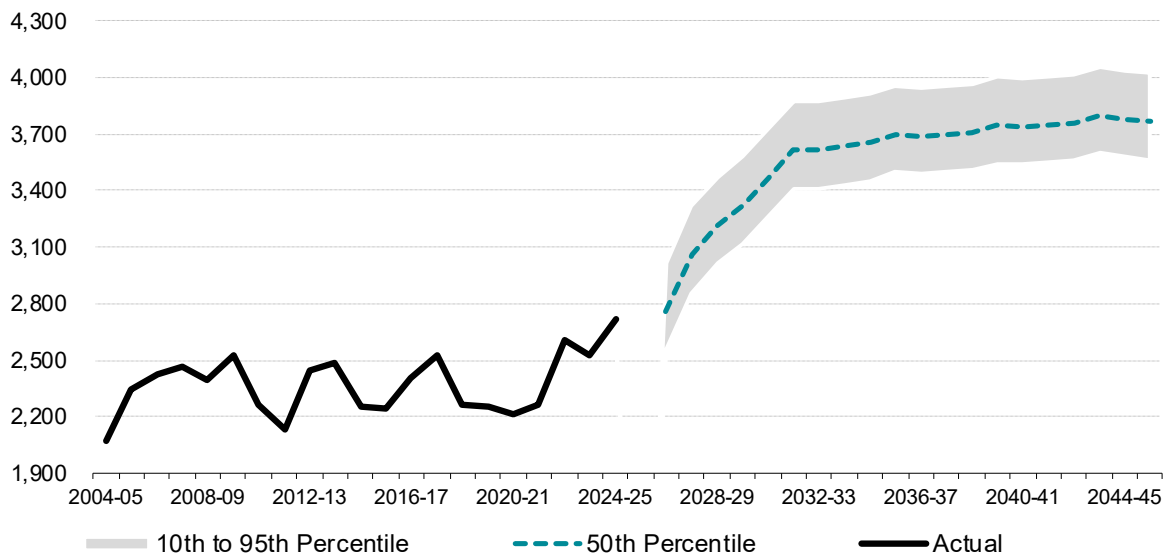


Figure 5. Forecast system winter peak (MW)

Peak Model Design

Peak-hour demands are integral components to the company's system planning. Peak-hour demands are forecast using a system of seven regression equations, one for the winter season (November to March), and one for peak summer season and five individual models for April to October (excluding June and July, see Appendix A2). The winter seasonal model was developed for this IRP to focus on the more recent volatility in weather responsiveness. 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 temperatures, and in some months, precipitation. The contribution to the system peak of the company's ESA customers is determined independently, using historical coincident peak factors, and then added to determine the system peak.

The forecast of average peak temperature is a key driver of the monthly system peak models. For the winter forecast, the normal average peak temperature drivers are calculated over the 1974 to 2024 period (the most recent 50 years). For the summer forecast, the most recent 20 years was used. In addition, the peak model develops peak scenarios based on historical percentiles of peak temperatures within each month. The details of the econometric peak models are found in Appendix A2.

CLASS SALES FORECAST

Residential

Sales to residential customers made up 34% of Idaho Power’s system sales in 2004 and 37% of system sales in 2024. The number of residential customers is projected to increase to just over 733,000 by December 2045. The residential load forecasts are reported in Table 4 and shown in Figure 6.

Table 4. Residential load growth (aMW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026–2045
95 th Percentile	766	782	825	872	0.7%
50 th Percentile	693	705	743	783	0.6%
10 th Percentile	643	652	686	721	0.6%

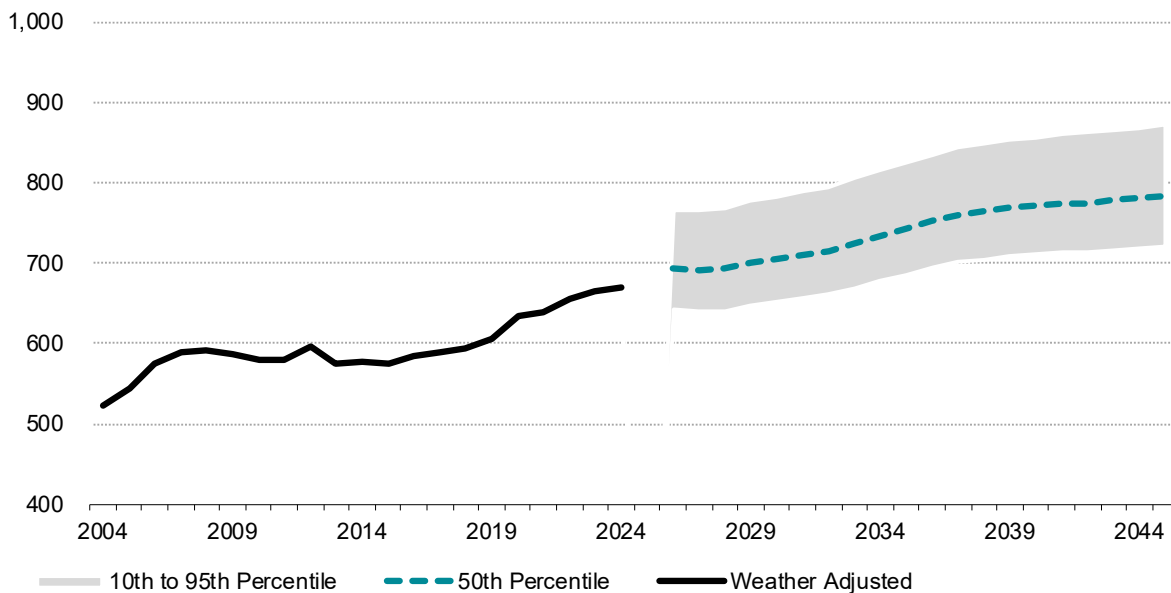


Figure 6. Forecast residential load (aMW)

A reduction in electricity prices in June 2003 and a recovery in the service-area economy caused average sales per residential customer to stabilize through 2007. However, since that time, conservation efforts have placed downward pressure on residential UPC. This trend is expected to continue, declining at 0.7% annually over the 2026–2045 planning period, as total residential UPC is expected to decrease to approximately 9,400 kWh by 2045. Residential UPC is shown in Figure 7.

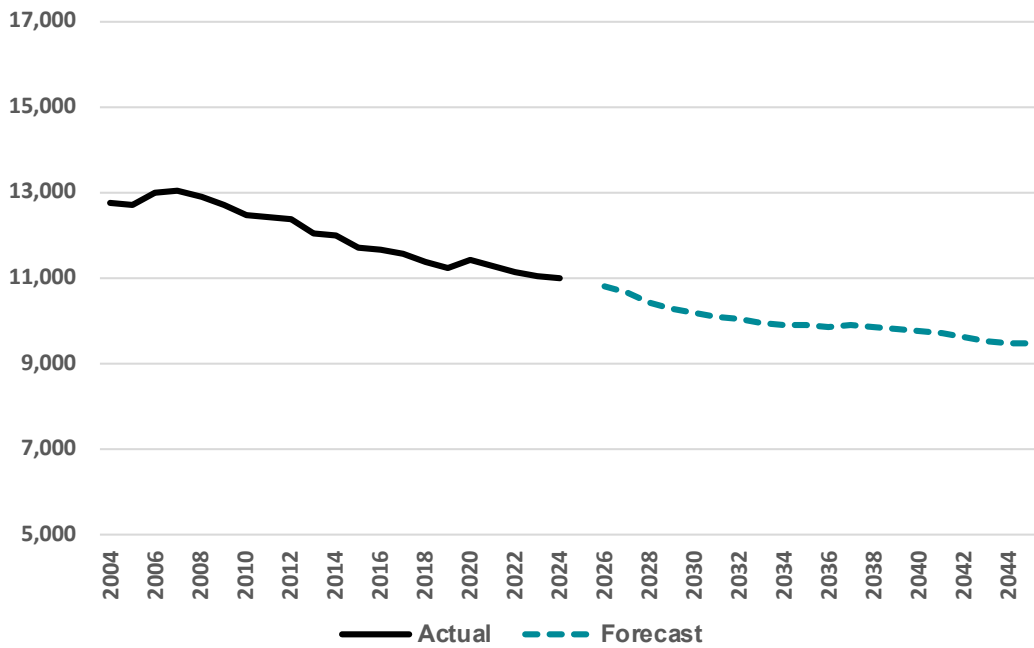


Figure 7. Forecast residential UPC (weather-adjusted kWh)

The residential customer forecast for 2026 to 2045 shows an average annual compound growth rate of 1.3% as shown in Figure 8.

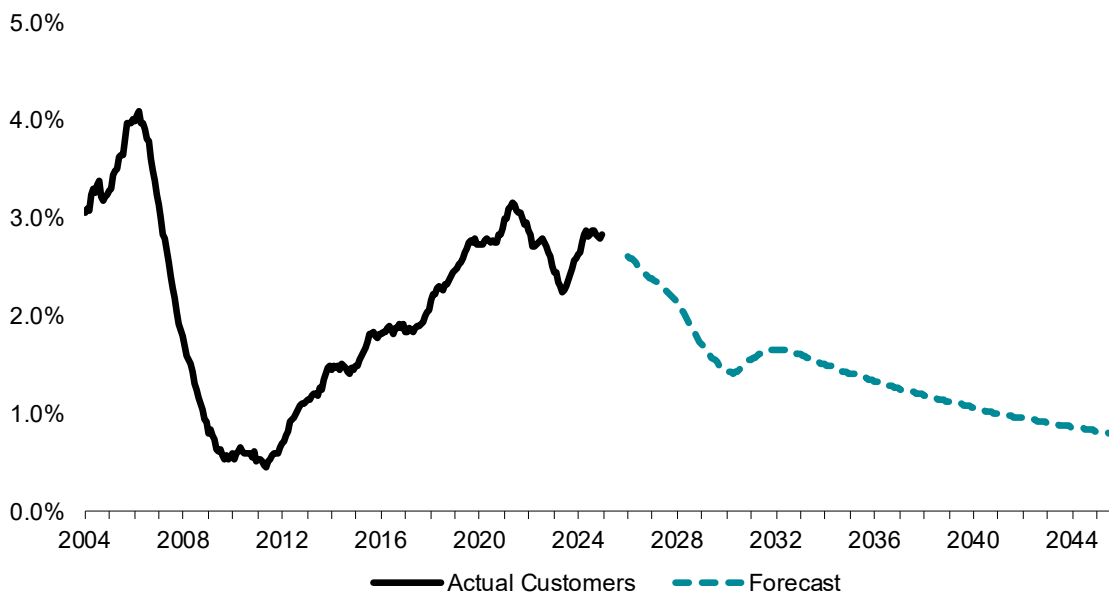


Figure 8. Residential customer growth rates (12-month change)

Final sales to residential retail customers can be framed as an equation that considers several factors affecting electricity sales to the residential sector. These factors include but are not limited to: 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.

The residential customer forecast model combines the strengths of ARIMA and ordinary least squares (OLS) methods through a weighted blending approach. ARIMA is used for short-term estimates, effectively capturing seasonality and recent trends based on historical customer counts. For long-term estimates, OLS incorporates broader growth patterns and includes the number of new households as a key variable, derived from Moody’s Analytics’ forecast of county housing stock and demographic data. A general schematic of the forecasting methodology using a statistically adjusted end-use (SAE) forecast model used in Idaho Power’s forecast residential sales is provided in Figure 9. The econometric equation portion of the residential SAE model and coefficients are provided in Appendix A2.

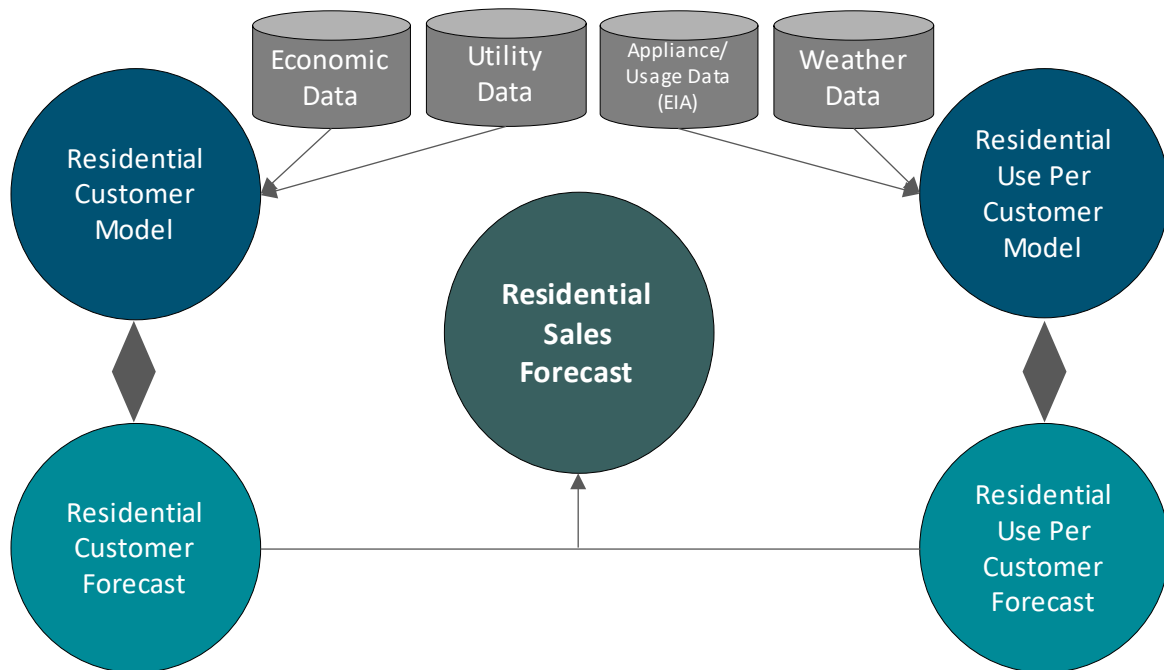


Figure 9. Residential sales forecast methodology framework

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. The commercial load forecast scenarios are reported in Table 5 and illustrated in Figure 10.

Table 5. Commercial load growth (aMW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026–2045
95 th Percentile	515	552	590	661	1.3%
50 th Percentile	496	531	568	635	1.3%
10 th Percentile	482	516	552	618	1.3%

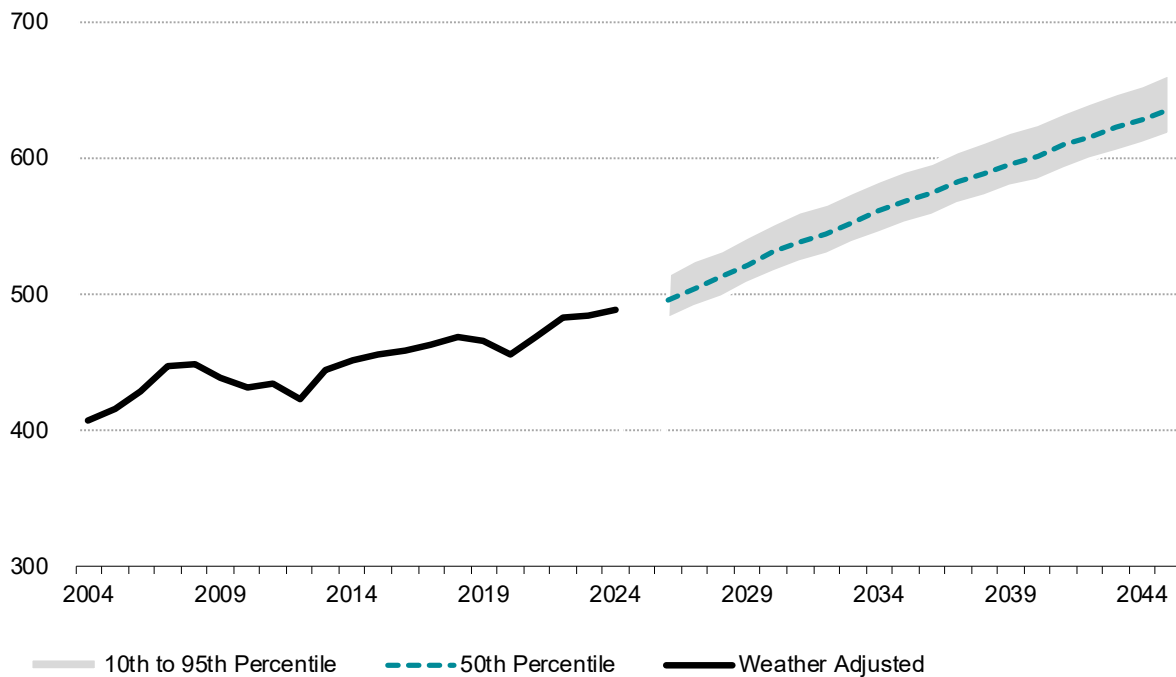


Figure 10. Forecast commercial load (aMW)

With a customer base of almost 79,500, the commercial class represents the diversity of the service area economy, ranging from residential sub-division pressurized irrigation to large manufacturers. Due to this diversity in load intensity and use—for analytical purposes—the category is 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 11 shows the breakdown of the categories and their relative sizes based on 2024 billed energy sales.

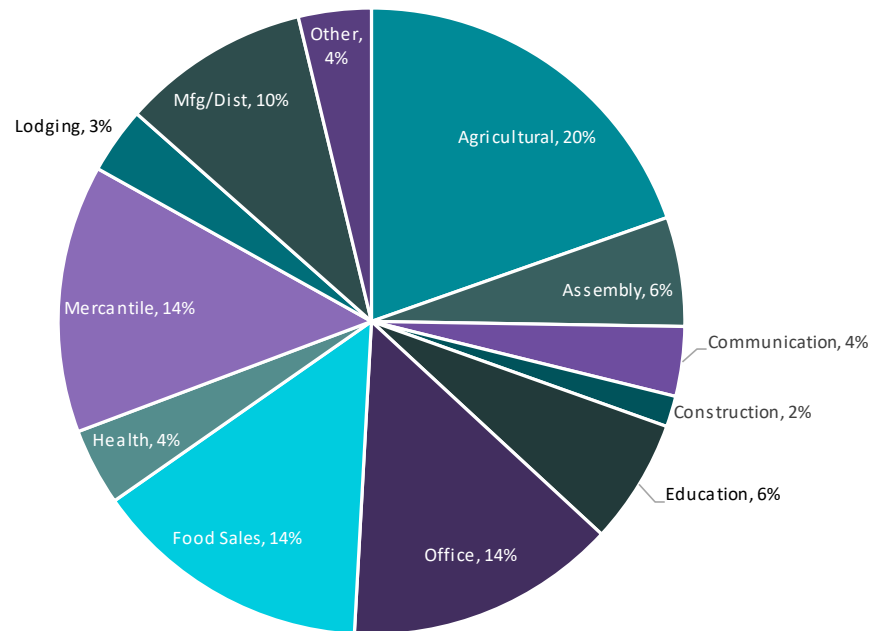


Figure 11. Commercial building share—energy use

Compared to 2022, agricultural-related sales represent a smaller share of the commercial sector in 2024, while food sales and mercantile represent a larger share. The number of commercial customers is expected to increase at an average annual rate of 1.4%, reaching nearly 107,500 customers by December 2045. In both 2004 and 2024, customers in the commercial category consumed approximately 27% of Idaho Power system sales.

Figure 12 shows historical and forecast average UPC for the entire commercial category. The commercial UPC metric in Figure 12 represents an aggregated metric for a highly diverse group of customers with significant differences in total energy UPC; nonetheless, it is instructive in aggregate for comparative purposes.

The UPC has declined at approximately 0.8% compounded annually from 2004 to 2024. However, the UPC has effectively been flat since 2020. The UPC is forecast to decrease at an annual rate of 0.1% over the planning period. For this category, common elements that drive use down include a shift toward service-based over industrial customer composition, adoption of energy efficiency technology, and electricity prices.

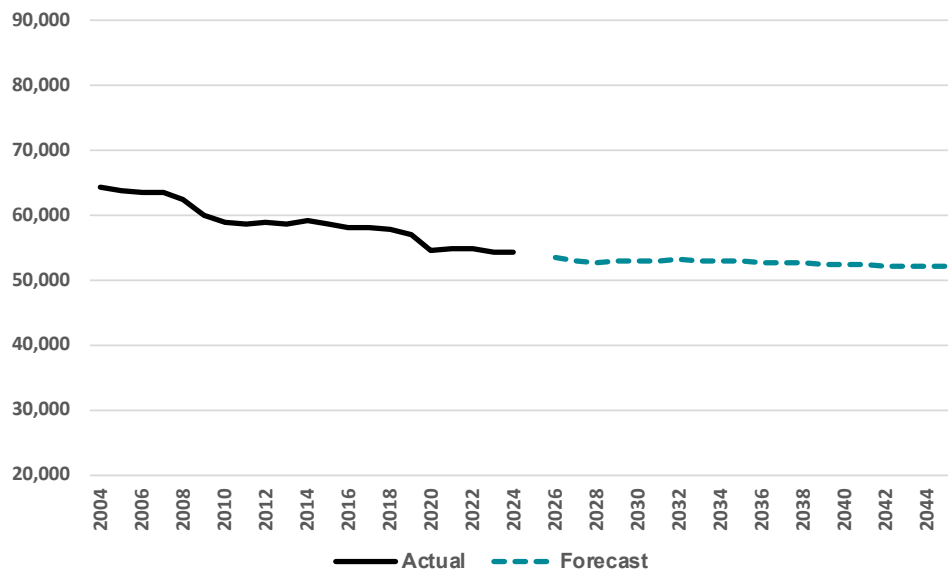


Figure 12. Forecast commercial UPC (weather-adjusted kWh)

Figure 13 shows the diversity in the commercial segment as well as the trend in UPC for these sectors. The figure shows the 2024 UPC for each segment relative to the 2018 UPC. A value greater than 1.0 indicates the UPC has risen over the period. The figure supports the general decline of the aggregated trend of Figure 12 but highlights differences in energy and economic dynamics within the heterogeneous commercial category not evident in the residential category.

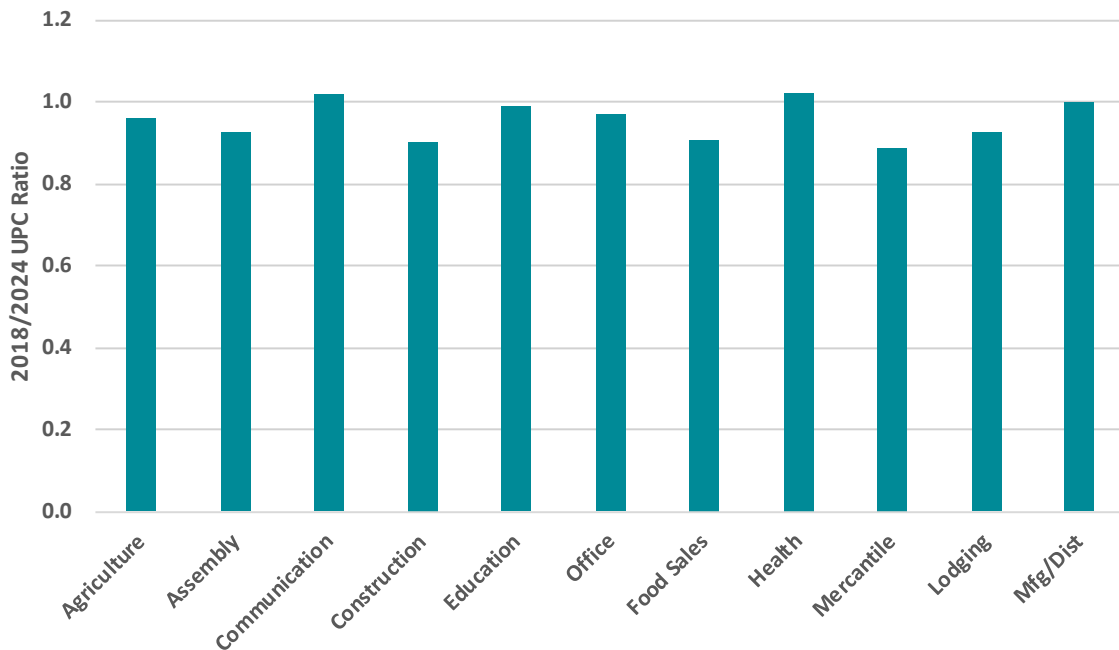


Figure 13. Commercial categories UPC, 2024 relative to 2018

Energy efficiency implementation is a large determinant in UPC decline over time. In the commercial sector, the primary energy efficiency technology impact has come from lighting; however, manufacturing motors are significant for that sector. Other influences on UPC include differences in price sensitivity, sensitivity to business cycles, 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 rate schedule administration, migrate to an industrial (Rate 19) category.

The commercial sales forecast equations consider several varying factors, as informed by the regression models, and vary depending on the category. Typical variables include corporate earnings; government spending; wholesale/retail trade; 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. Commercial model equations and coefficients are provided in Appendix A2.

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% of Idaho Power’s system sales. By December 2024, the number of industrial customers had risen to 140, representing approximately 16% of system sales. Customer counts in this class are impacted by migration to and from the commercial class as dictated by rate schedule administration. However, customer count growth is primarily illustrative of the positive economic conditions in the service area. Customers with load greater than 20 MW are known as ESA customers and are addressed in the Additional Firm Load section of this document.

The industrial load forecast is reported in Table 6 and illustrated in Figure 14. 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 alternative percentile weather scenarios are identical to the 50th-percentile industrial load scenario.

Table 6. Industrial load growth (aMW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026–2045
Industrial Load Forecast	276	284	294	318	0.7%

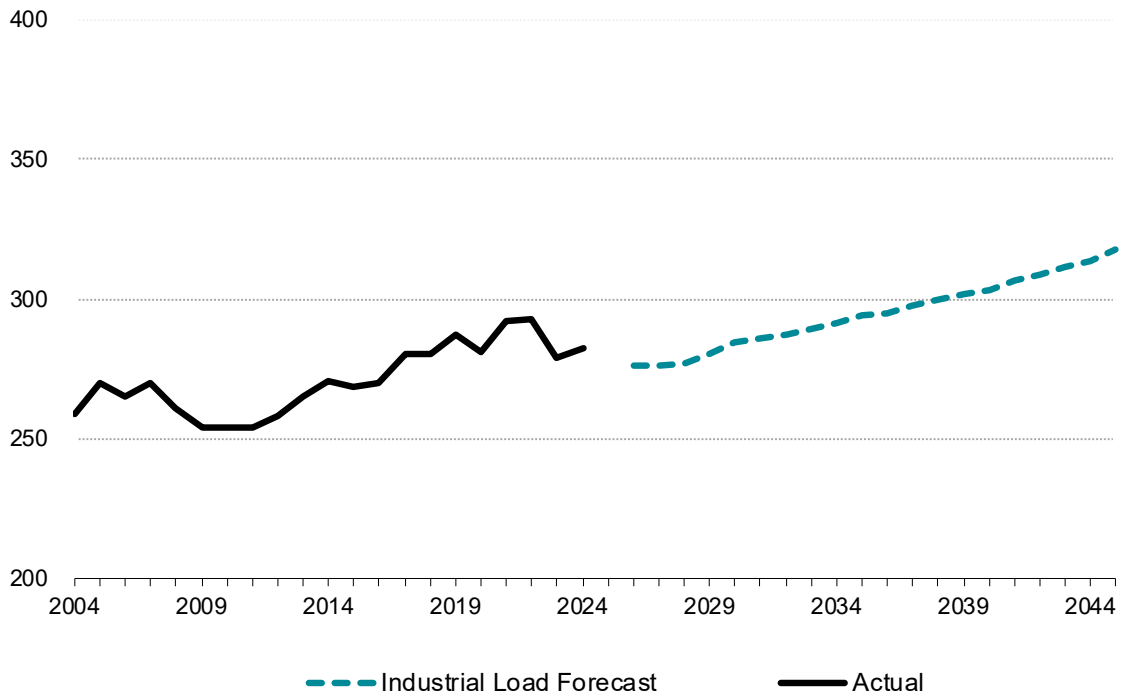


Figure 14. Forecast industrial load (aMW)

Figure 15 illustrates the 2024 share of each of the industrial customer categories. By far, the largest share of electricity was consumed by the food manufacturing sector (34%) and dairy-related manufacturing (22%). The categorization scheme includes a range of serviceproviding industrial building types (assembly, lodging, 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.

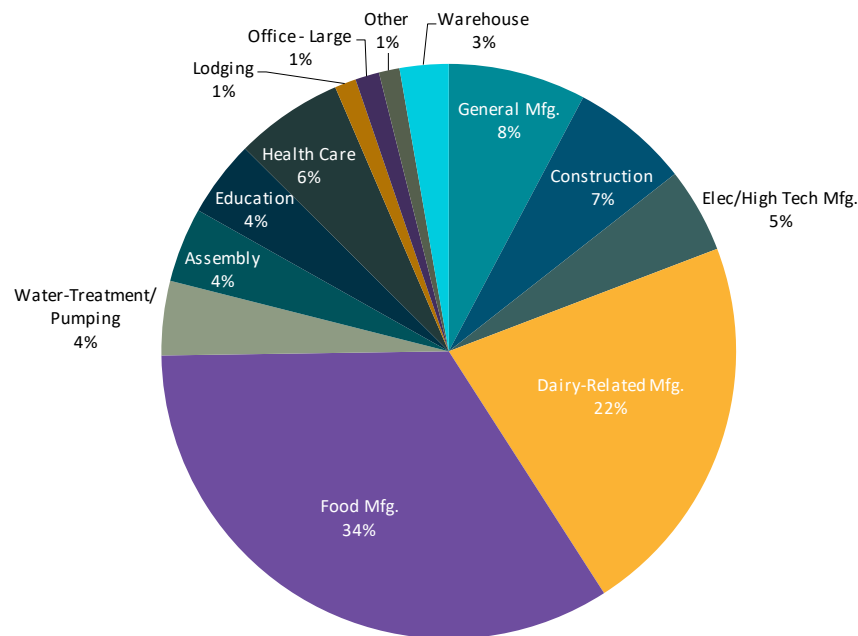


Figure 15. Industrial electricity consumption by industry group (based on 2024 sales)

Commercial and Industrial Modeling Process

The modeling process for both the Commercial and Industrial sectors are similar and use Ordinary Least Squares regression models to forecast load. However, because each sector has varying drivers for energy use, a different set of explanatory variables are used for each model. Both the Commercial and Industrial sectors are further divided into manufacturing and service subsector models. This yields four model outputs in total. After modeling, the commercial service and manufacturing models are combined, and the industrial service and manufacturing models are combined.

The process begins by gathering 20 years of historic load by sector and subsector as the dependent variable. Because energy efficiency has a large impact on load, its impacts are removed by adding the estimated energy reduction from Idaho Power’s energy efficiency programs to the dependent variable.

Next, potential explanatory or independent variables are gathered. These include historic and forecast economic, employment, population, energy price, weather, and internal customer data. The sources of this data include National Ocean and Atmospheric Administration (NOAA), Moody’s Economics, Woods and Poole Economics, and internal databases.

Each potential explanatory variable is first screened for which model(s) it would potentially fit into, if any. For example, dairy earnings would be used in the manufacturing models, but not

service models, as dairy load is categorized into the manufacturing subsectors. Once this is complete, a grid search method is used to combine all the sets of explanatory variables from two to five variable combinations. Every combination of explanatory variables is run for its respective model. For each model run, there is a set of filter criteria that must be met for the model to move forward in the process. All variables must be statistically significant, auto-correlation cannot exist in the model, and the Mean Absolute Percentage Error (MAPE) must be less than 5%.

If the model passes these filter parameters, it is fed into an out-of-sample test where the predictive power of the model is measured over the previous four years (20% of the training history used in the model). The output of all models is then sorted by the Root Mean Squared Error of this four-year test. The list of model parameters is output and the final model selected where growth rates are reasonable given the recent history and understanding of the future. Because this calculation is a forecast without the impacts of energy efficiency, the forecast energy efficiency from Idaho Power’s Potential Study is subtracted from the final answer.

Figure 16 shows a summary of the general forecasting methodology used for both the commercial and industrial sectors.

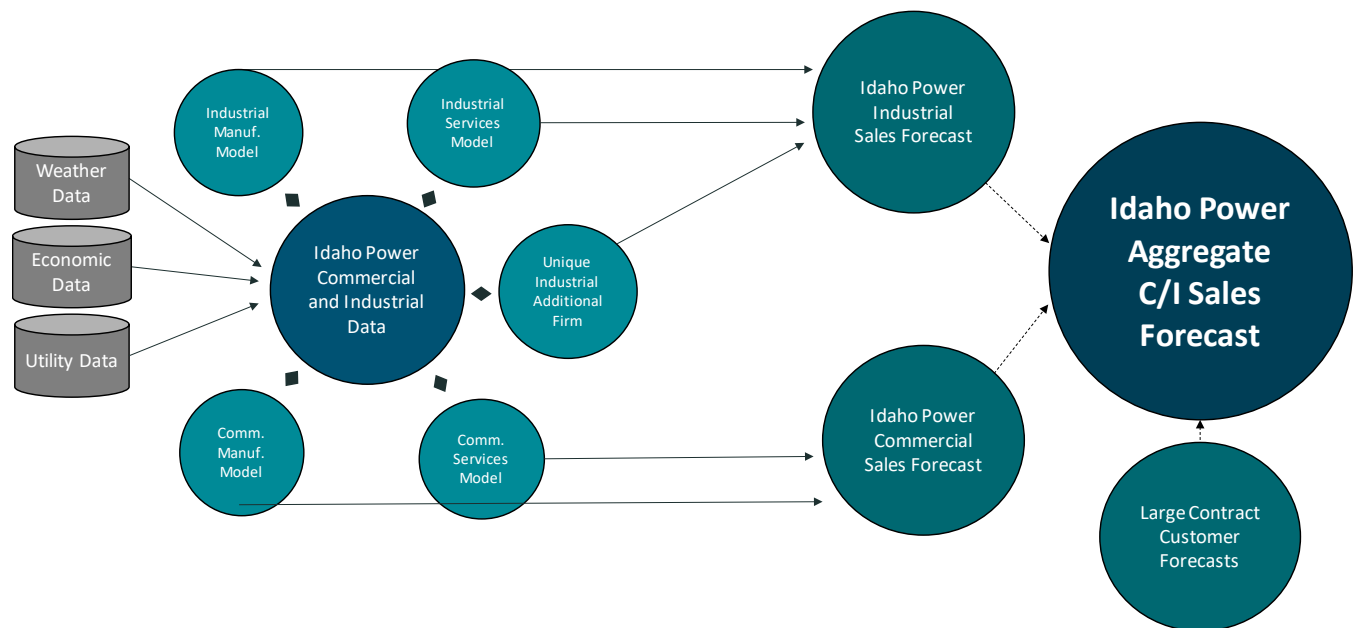


Figure 16. Commercial and industrial sales forecast methodology

Irrigation

The irrigation category is comprised of agricultural irrigation service customers. Service under this schedule is applicable to 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 irrigation class is highly sensitive to weather, resulting in a wide distribution of potential outcomes as shown in the bands summarized in Table 7 and illustrated in Figure 17.

Table 7. Irrigation load growth (aMW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026–2045
95 th Percentile	257	265	270	282	0.5%
50 th Percentile	217	225	230	242	0.6%
10 th Percentile	171	178	183	196	0.7%

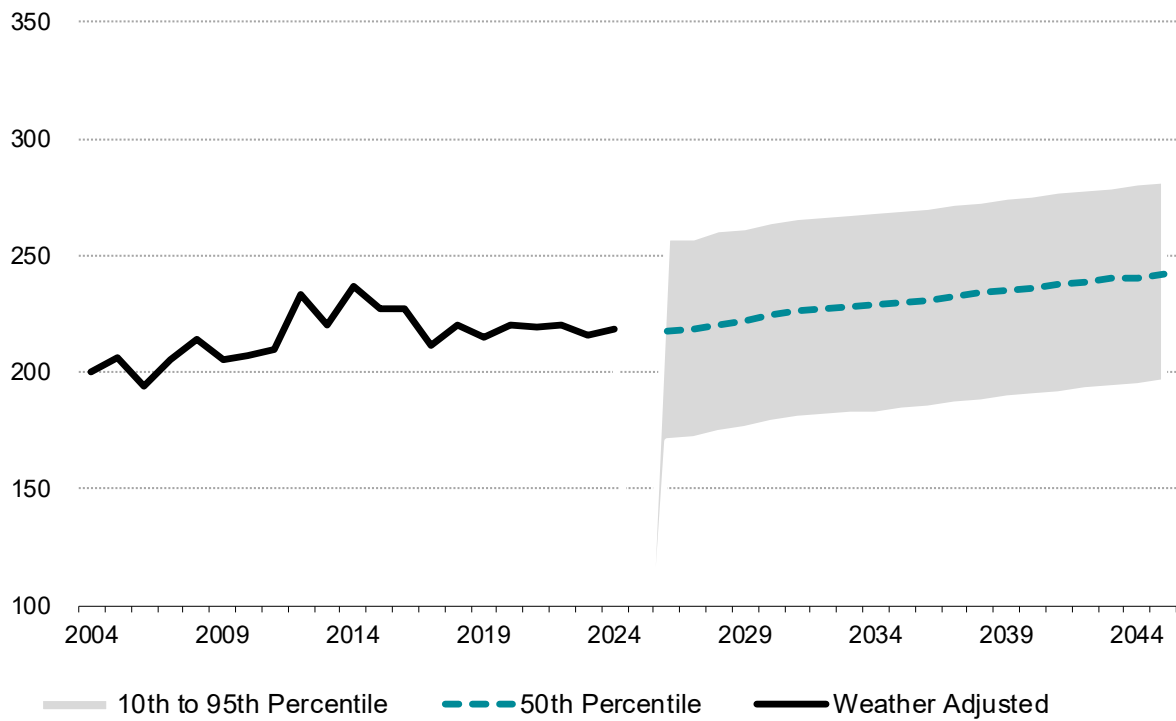


Figure 17. Forecast irrigation load (aMW)

In the highly seasonal irrigation sector, over 97% of the annual energy is billed during the six months from May through October, and nearly half the annual energy is billed in just two months: July and August. In a normal July, irrigation pumping accounts for roughly 25% of the energy consumed during the hour of the annual system peak and nearly 30% of the energy consumed during July for general business sales.

The 2025 IRP irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; Palmer Z Index (calculated by NOAA from a combination of precipitation, temperature, and soil moisture data); Moody’s Producer Price Index: Prices Received by Farmers, All Farm Products; residential customers added per year; and annual maximum irrigation customer counts.

Actual irrigation electricity sales have grown from the 1970 level of 816,000 MWh to a peak amount of 2,097,000 MWh in 2013. In 1977, irrigation sales reached a maximum proportion of 20% of Idaho Power system sales. In 2024, the irrigation proportion of system sales was 12% due to the much higher relative growth in other customer classes.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2024, the number of active irrigation accounts had increased to 21,147 and is projected to be just over 26,600 at the end of the planning period in 2045.

As with other classes, average UPC 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 as customers are converting previously furrow-irrigated land to sprinkler-irrigated land. The conversion rate is slow and the kWh UPC 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 rate schedule administration requires the company to serve requests for electric service greater than 20 MW under a special contract, or ESA, schedule negotiated between Idaho Power and each large-power customer. The ESA and rate schedule are approved by the appropriate state commission. An ESA allows a 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 for ESA customers, including Brisbie, LLC (Meta Platforms, Inc.); Idaho National Laboratory (INL); Lamb Weston; Micron Idaho Semiconductor Manufacturing; Micron Technology, Inc.; Simplot Caldwell; Simplot Pocatello Don Plant; along with other committed large load customers who have entered into procurement or construction agreements with Idaho Power, but who have not yet executed an ESA. These ESA and other committed large load customers comprise the entire forecast category labeled "additional firm load".

Projected additional firm load growth is summarized in Table 8 and illustrated in Figure 18. As with the industrial class, additional firm load variability is to a large degree not associated with weather conditions. Therefore, the forecasts in alternative percentile weather scenarios are identical to the 50th-percentile additional firm load scenario.

Table 8. Additional firm load growth (aMW)

Growth	2026	2030	2035	2045	Annual Growth Rate 2026–2045
Additional Firm Load Forecast	257	875	1,065	1,072	7.8%

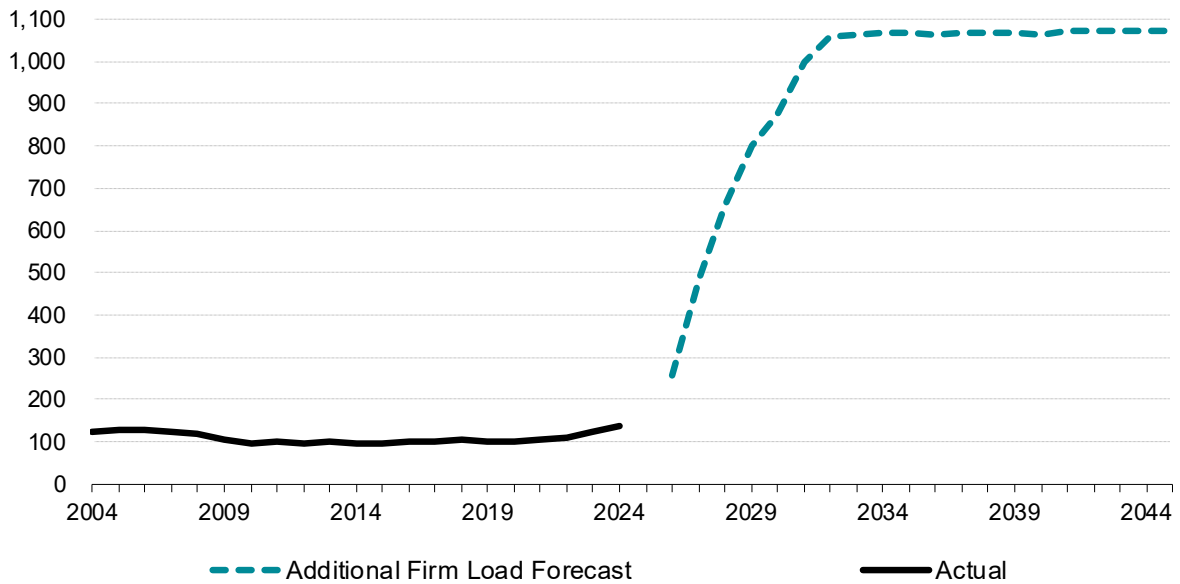


Figure 18. Forecast additional firm load (aMW)

Brisbie, LLC (Meta Platforms, Inc.)

Idaho Power and Meta executed an ESA which was approved by the IPUC in May 2023. Meta’s \$800 million data center is under construction in Kuna, Idaho, and is on track for completion in 2025. Meta will support 100% of its operations through the addition of new renewable resources connected to Idaho Power’s system. The incremental renewables to meet this goal have been fully contracted through Clean Energy Your Way (CEYW) construction arrangements, with the first contracted solar project meeting its in-service date of March 2025.

Idaho National Laboratory (INL)

Idaho National Laboratory (INL), a U.S. Department of Energy facility, is a leading center for nuclear energy research and development, focusing on nuclear safety, clean energy solutions, and national security. Much of the work to achieve this mission at INL is performed in government-owned facilities on the 890-square-mile INL site, approximately 50 miles west of Idaho Falls, Idaho. INL is a critical economic driver and important asset to the state of Idaho with over 6,400 employees.

Lamb Weston

The Lamb Weston facility in American Falls, Idaho, has a history rooted in the company's founding in 1961 and is now among the largest frozen potato processing plants in the world following a \$415 million expansion that became operational in August 2024. This expansion project included a new french fry line, a chopped-and-form line, and a new cold storage facility. The expansion created 135 new jobs and is a major economic boost to the eastern Idaho economy.

Micron Idaho Semiconductor Manufacturing

In 2022, Micron announced plans to construct a \$15 billion leading-edge memory manufacturing facility in Boise. This new fab will be co-located with Micron's existing leading-edge research and development campus. Once operational, with meaningful DRAM output projected for 2027, this facility will add 2,000 jobs to the Boise metro economy. Idaho Power filed a new ESA for the Micron Idaho Semiconductor Manufacturing facility with the IPUC in December 2024.

Micron Technology

Micron Technology operates its global headquarters and research and development fabrication campus in Boise, Idaho. Founded in Boise in 1978, Micron has grown to become a global leader in memory and storage solutions, ranking in the top 10 semiconductor companies around the world. In addition to its R&D focus, the Micron Boise HQ campus performs a variety of other activities, including product design and support, quality assurance, systems integration and related manufacturing, and corporate and general services.

Simplot Caldwell

The 420,000 square-foot Simplot potato processing plant in Caldwell, Idaho, was built on the site of Simplot's original WWII potato dehydrating plant and is a state-of-the-art facility that processes frozen potato products, including french fries. This site includes an energy efficient high-bay freezer that minimizes energy loss and allows for a smaller refrigeration system to maintain the freezer at -5°F.

Simplot Pocatello Don Plant

Located just outside Pocatello, Idaho, the Simplot Don Plant produces high-quality phosphate fertilizer, feed phosphates, and industrial products from ore mined at the Smoky Canyon Mine on the Idaho-Wyoming border. The plant has been in operation for over 80 years and employs more than 400 employees in the area.

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 EE program managers and utilizes the updated potential study, most recently developed by Applied Energy Group (AEG). EE 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 DOE and is consistent with the 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 above information is used as a benchmark against the AEG achievable potential forecast for residential and/or adjusted if needed.

While DOE data is available for the commercial sector, Idaho Power's test modeling of the data indicates 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 EE and AEG potential study forecast to recognize energy efficiency. DOE data is not available for the industrial sector, and EE is incorporated into the forecast in a similar manner as the commercial 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 (EE 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 EE and codes and standards.

For the ESAs noted in the previous section, Idaho Power utilizes the energy forecasts the customers provide and does not make any energy efficiency adjustments.

A more detailed description of EE 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

The number of customers transitioning from standard to on-site generation has risen steadily over the past 10 years; particularly for residential customers. The current population of on-site generation residential customers is almost 3% of the population of retail customers.

The installation of generation and storage equipment at customer sites causes 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. The long-term sales forecast was adjusted downward to reflect the impact of the increase in the number customers with on-site generation, specifically solar generation, connecting to Idaho Power's system.

On-site generation customer usage was compared to their usage while on the parent rate schedule, or prior to becoming an on-site generation customer. The resulting average monthly impact per customer decrement (in kWh) was then multiplied by the forecasts for the appropriate on-site generation customer grouping. This estimates the future energy decrement to the sales forecast. The forecast of on-site generation customers serves as a function of historical trends and approved regulatory billing method authorizations.

At the end of the forecast period, 2045, the annual residential sales forecast reduction was about 26 aMW, the commercial reduction was 4 aMW, and the irrigation reduction was 3 aMW.

Electrification

The load forecast includes an update of the impact of plug-in electric vehicles (PEV) on system load to reflect the future impact of this relatively new and evolving source of energy use. While electric vehicle (EV) consumer adoption rates in Idaho Power's service area remain relatively low, the continued technological advancement, limiting attributes of vehicle range refueling time, and charging availability and technology 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. Idaho Power receives detailed registration data from Idaho Transportation Department (ITD) and Oregon Department of Energy. The data provides county-level registration which provides a basis for determining Idaho Power service area-vehicle inventory. Other data sources for monitoring the outlook for PEV adoption include the DOE and Moody's Analytics.

The evolution of the PEV market shows high adoption continues to be evident in high-density and affluent population centers. Idaho Power 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 area.

Heat pumps are also an evolving source of electrification. Idaho Power forecasts residential heat pump saturations and efficiencies in the residential statistically adjusted end use models. Data are provided from the DOE's Annual Energy Outlook and calibrated to Idaho Power's service area using Idaho Power's end use survey, which is conducted approximately every five years.

Demand Response

Existing and future demand response program impacts are not incorporated into the sales and load forecast. All demand response programs are treated as a supply-side resource and would not be prudent to include a supply-side resource decrement into the sales and load forecast.

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 some of the individual sales forecast models (see Appendix A2).

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 9. 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 9. Residential fuel-price escalation (2026–2045) (average annual percent change)

	Nominal	Real*
Electricity—2025 IRP	1.3%	-0.9%
Electricity—2023 IRP	-0.1%	-2.2%
Natural Gas	1.0%	-1.2%

*Adjusted for inflation

The electricity price forecast used to prepare the sales and load forecast in the 2025 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2023 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2023 IRP sales and load forecast, the electricity price forecast used to prepare the 2025 IRP sales and load forecast yields higher future prices. The retail prices are mostly lower throughout the planning period which can impact the sales forecast, a consequence of the inverse relationship between electricity prices and electricity demand.

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. In the 2025 IRP price forecast, the long-term direction in real electricity prices and real natural gas prices (adjusted for inflation) is downward.

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 bill periods to calendar months to synchronize them with the 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.

Hourly Load Forecast

Idaho Power leverages several years of advanced metering infrastructure (AMI) data in its hourly load forecasting methodology. AMI data is utilized to inform an hourly load forecast that conforms with forecast methods mentioned throughout this document. It is important to note

that the monthly modeling process, described earlier, is the forecast used in the IRP. The hourly load forecast methodology, described below, allocates the monthly model regressions to each hour of the year.

Hourly Load Forecast Methodology

The company uses the stability of monthly regression data as noted in this document to calibrate and ground an hourly forecast. Each monthly class forecast is shaped to hourly values using a weather-normalized historic class shape, detailed below. Certain non-traditional components of the forecast with load shapes that deviate from the base class shape, such as electric vehicles and solar installations, are modeled separately with their own load shape. The class hourly forecasts and auxiliary hourly forecasts are summed together where total monthly energy equals the summed monthly forecast, and the peak hour of each month equals the system peak forecast.

Technical Specifications of Hourly Load Forecasting

The hourly allocation model uses two non-linear nodes and is hinged on currently accepted load forecasting processes. The result of this methodology brings statistical confidence of hourly load modeling while still conforming to the stability of the traditional methodology of monthly sales forecasting as mentioned above.

An industry approach to weather responsiveness is to utilize a linear model based on an HDD or CDD level of 65 degrees Fahrenheit (°F) (actual point may differ by local utility weather characteristics). Utilities 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 65°F. This methodology works 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.

The design outputs a single series of hourly energy and uses a logistic activation function with a linear function to address the calendar (weekend, weekday, holidays, etc.) effects.

A distinct model is developed for each hour of the year to capture the full spectrum of temperature responsiveness throughout a day. For each non-linear hourly model, a derivative value is calculated along the curve to obtain the relationship of energy sales to temperature. This also facilitates the construction of lagged weather impacts, 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 area. 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 uses the 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 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.

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 more than one year. Currently, 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 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

Historical Company System Sales and Load, 2004–2024 (weather adjusted)

Year	Billed Sales		Average Load (aMW)
	(thousands of MWh)	Percent Change	
2004	13,312		1,515
2005	13,655	2.6%	1,559
2006	13,984	2.4%	1,596
2007	14,364	2.7%	1,640
2008	14,410	0.3%	1,641
2009	14,015	-2.7%	1,600
2010	13,801	-1.5%	1,575
2011	13,805	0.0%	1,576
2012	14,045	1.7%	1,599
2013	14,024	-0.1%	1,601
2014	14,253	1.6%	1,627
2015	14,095	-1.1%	1,609
2016	14,307	1.5%	1,629
2017	14,390	0.6%	1,643
2018	14,557	1.2%	1,662
2019	14,725	1.2%	1,681
2020	14,903	1.2%	1,697
2021	15,139	1.6%	1,728
2022	15,331	1.3%	1,750
2023	15,404	0.5%	1,758
2024	15,814	2.7%	1,800

Projected Company System Sales and Load, 2026–2045

Year	Billed Sales		Average Load (aMW)
	(thousands of MWh)	Percent Change	
2026	16,990	5.8%	2,102
2027	19,075	12.3%	2,348
2028	20,746	8.8%	2,539
2029	22,114	6.6%	2,709
2030	22,942	3.7%	2,807
2031	24,172	5.4%	2,952
2032	24,884	2.9%	3,028
2033	25,025	0.6%	3,054
2034	25,220	0.8%	3,078
2035	25,401	0.7%	3,099
2036	25,593	0.8%	3,115
2037	25,733	0.5%	3,140
2038	25,850	0.5%	3,154
2039	25,974	0.5%	3,169
2040	26,124	0.6%	3,179
2041	26,258	0.5%	3,203
2042	26,360	0.4%	3,216
2043	26,487	0.5%	3,231
2044	26,627	0.5%	3,240
2045	26,724	0.4%	3,260

Residential Load

Historical Residential Sales and Load, 2004-2024 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2004	360,462		12,665	4,565		520
2005	373,602	3.6%	12,672	4,734	3.7%	540
2006	387,707	3.8%	12,951	5,021	6.1%	573
2007	397,286	2.5%	13,005	5,167	2.9%	590
2008	402,520	1.3%	12,860	5,177	0.2%	589
2009	405,144	0.7%	12,696	5,144	-0.6%	587
2010	407,551	0.6%	12,428	5,065	-1.5%	578
2011	409,786	0.5%	12,357	5,064	0.0%	578
2012	413,610	0.9%	12,370	5,116	1.0%	582
2013	418,892	1.3%	12,023	5,037	-1.6%	575
2014	425,036	1.5%	11,962	5,084	1.0%	580
2015	432,275	1.7%	11,679	5,049	-0.7%	576
2016	440,362	1.9%	11,561	5,091	0.8%	580
2017	448,800	1.9%	11,497	5,160	1.4%	589
2018	459,128	2.3%	11,314	5,195	0.7%	593
2019	471,298	2.7%	11,183	5,271	1.5%	602
2020	484,433	2.8%	11,361	5,504	4.4%	627
2021	499,216	3.1%	11,215	5,599	1.7%	639
2022	512,803	2.7%	11,131	5,708	2.0%	652
2023	525,110	2.4%	10,996	5,774	1.2%	659
2024	539,849	2.8%	11,002	5,939	2.9%	676

Projected Residential Sales and Load, 2026–2045

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2026	568,636	2.5%	10,673	6,069	1.4%	693
2027	581,567	2.3%	10,404	6,051	-0.3%	691
2028	592,847	1.9%	10,273	6,091	0.7%	693
2029	602,168	1.6%	10,182	6,131	0.7%	700
2030	610,998	1.5%	10,109	6,177	0.7%	705
2031	620,874	1.6%	10,021	6,222	0.7%	710
2032	631,045	1.6%	9,958	6,284	1.0%	715
2033	640,893	1.6%	9,906	6,349	1.0%	725
2034	650,266	1.5%	9,886	6,429	1.3%	734
2035	659,226	1.4%	9,871	6,507	1.2%	743
2036	667,783	1.3%	9,881	6,598	1.4%	751
2037	675,974	1.2%	9,855	6,662	1.0%	761
2038	683,842	1.2%	9,788	6,693	0.5%	764
2039	691,369	1.1%	9,737	6,732	0.6%	768
2040	698,528	1.0%	9,699	6,775	0.6%	771
2041	705,370	1.0%	9,602	6,773	0.0%	773
2042	711,969	0.9%	9,526	6,782	0.1%	774
2043	718,324	0.9%	9,488	6,816	0.5%	778
2044	724,432	0.9%	9,458	6,852	0.5%	780
2045	730,310	0.8%	9,395	6,861	0.1%	783

Commercial Load

Historical Commercial Sales and Load, 2004–2024 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2004	55,576		64,187	3,567		406
2005	57,145	2.8%	63,648	3,637	2.0%	415
2006	59,050	3.3%	63,720	3,763	3.4%	430
2007	61,640	4.4%	63,435	3,910	3.9%	446
2008	63,492	3.0%	62,286	3,955	1.1%	450
2009	64,151	1.0%	59,849	3,839	-2.9%	438
2010	64,421	0.4%	58,899	3,794	-1.2%	433
2011	64,921	0.8%	58,547	3,801	0.2%	434
2012	65,599	1.0%	58,968	3,868	1.8%	440
2013	66,357	1.2%	58,656	3,892	0.6%	444
2014	67,113	1.1%	59,066	3,964	1.8%	453
2015	68,000	1.3%	58,644	3,988	0.6%	455
2016	68,883	1.3%	58,179	4,008	0.5%	456
2017	69,850	1.4%	57,905	4,045	0.9%	462
2018	71,104	1.8%	57,787	4,109	1.6%	469
2019	72,332	1.7%	56,974	4,121	0.3%	470
2020	73,703	1.9%	54,553	4,021	-2.4%	458
2021	75,284	2.1%	54,773	4,123	2.6%	471
2022	76,674	1.8%	54,917	4,211	2.1%	481
2023	77,953	1.7%	54,153	4,221	0.3%	482
2024	79,101	1.5%	54,441	4,306	2.0%	490

Projected Commercial Sales and Load, 2026–2045

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2026	82,092	1.9%	52,845	4,338	0.8%	495
2027	83,559	1.8%	52,836	4,415	1.8%	504
2028	84,972	1.7%	52,887	4,494	1.8%	512
2029	86,294	1.6%	52,916	4,566	1.6%	521
2030	87,526	1.4%	53,091	4,647	1.8%	530
2031	88,761	1.4%	53,114	4,714	1.5%	538
2032	90,086	1.5%	53,043	4,778	1.4%	544
2033	91,460	1.5%	52,907	4,839	1.3%	552
2034	92,835	1.5%	52,848	4,906	1.4%	560
2035	94,193	1.5%	52,794	4,973	1.4%	568
2036	95,534	1.4%	52,670	5,032	1.2%	573
2037	96,859	1.4%	52,582	5,093	1.2%	581
2038	98,168	1.4%	52,493	5,153	1.2%	588
2039	99,462	1.3%	52,382	5,210	1.1%	595
2040	100,739	1.3%	52,336	5,272	1.2%	600
2041	101,996	1.2%	52,287	5,333	1.2%	609
2042	103,237	1.2%	52,227	5,392	1.1%	615
2043	104,464	1.2%	52,187	5,452	1.1%	622
2044	105,679	1.2%	52,115	5,507	1.0%	627
2045	106,879	1.1%	52,085	5,567	1.1%	635

Irrigation Load

Historical Irrigation Sales and Load, 2004–2024 (weather adjusted)

Year	Maximum	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
	Active Customers					
2004	16,297		107,670	1,755		200
2005	16,936	3.9%	103,736	1,757	0.1%	201
2006	17,062	0.7%	98,871	1,687	-4.0%	193
2007	17,001	-0.4%	104,674	1,780	5.5%	203
2008	17,428	2.5%	106,543	1,857	4.3%	211
2009	17,708	1.6%	103,999	1,842	-0.8%	210
2010	17,846	0.8%	101,108	1,804	-2.0%	206
2011	18,292	2.5%	98,678	1,805	0.0%	206
2012	18,675	2.1%	103,196	1,927	6.8%	219
2013	19,017	1.8%	100,716	1,915	-0.6%	219
2014	19,328	1.6%	103,498	2,000	4.4%	228
2015	19,756	2.2%	93,988	1,857	-7.2%	212
2016	20,042	1.4%	98,602	1,976	6.4%	225
2017	20,246	1.0%	90,636	1,835	-7.1%	209
2018	20,459	1.1%	92,670	1,896	3.3%	216
2019	20,566	0.5%	93,264	1,918	1.2%	219
2020	20,804	1.2%	96,707	2,012	4.9%	229
2021	21,066	1.3%	92,385	1,946	-3.3%	222
2022	21,324	1.2%	89,246	1,903	-2.2%	217
2023	21,537	1.0%	86,491	1,863	-2.1%	213
2024	21,706	0.8%	87,134	1,891	1.5%	215

Projected Irrigation Sales and Load, 2026–2045

Year	Maximum		kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
	Active Customers	Percent Change				
2026	22,285	-3.3%	85,461	1,905	0.4%	217
2027	22,538	1.1%	84,755	1,910	0.3%	218
2028	22,794	1.1%	84,894	1,935	1.3%	220
2029	23,050	1.1%	84,497	1,948	0.7%	222
2030	23,304	1.1%	84,434	1,968	1.0%	225
2031	23,559	1.1%	84,159	1,983	0.8%	226
2032	23,812	1.1%	83,693	1,993	0.5%	227
2033	24,066	1.1%	83,066	1,999	0.3%	228
2034	24,321	1.1%	82,449	2,005	0.3%	229
2035	24,578	1.1%	81,988	2,015	0.5%	230
2036	24,830	1.0%	81,615	2,026	0.6%	231
2037	25,087	1.0%	81,245	2,038	0.6%	233
2038	25,342	1.0%	80,870	2,049	0.6%	234
2039	25,597	1.0%	80,497	2,060	0.5%	235
2040	25,850	1.0%	80,131	2,071	0.5%	236
2041	26,103	1.0%	79,767	2,082	0.5%	238
2042	26,360	1.0%	79,396	2,093	0.5%	239
2043	26,612	1.0%	79,032	2,103	0.5%	240
2044	26,867	1.0%	78,658	2,113	0.5%	241
2045	27,124	1.0%	78,280	2,123	0.5%	242

Industrial Load

Historical Industrial Sales and Load, 2004–2024 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2004	117		19,414,549	2,268		258
2005	126	7.9%	18,647,778	2,351	3.7%	268
2006	127	1.0%	18,253,137	2,324	-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%	263
2009	124	4.0%	17,997,866	2,226	-3.6%	254
2010	121	-2.0%	18,402,238	2,231	0.2%	255
2011	120	-1.1%	18,586,468	2,229	-0.1%	254
2012	115	-4.2%	19,768,964	2,272	1.9%	259
2013	114	-0.7%	20,281,837	2,314	1.9%	264
2014	113	-0.7%	20,863,653	2,363	2.1%	270
2015	116	2.8%	20,266,704	2,359	-0.1%	269
2016	118	1.4%	20,001,422	2,362	0.1%	269
2017	117	-1.1%	20,993,241	2,453	3.8%	280
2018	115	-1.6%	21,279,252	2,447	-0.2%	279
2019	124	8.0%	20,284,864	2,520	3.0%	288
2020	124	-0.3%	19,912,671	2,466	-2.2%	281
2021	124	0.0%	20,668,004	2,559	3.8%	292
2022	123	-0.8%	20,864,958	2,563	0.1%	293
2023	128	4.2%	19,176,586	2,455	-4.2%	280
2024	134	4.4%	18,546,371	2,477	0.9%	282

Projected Industrial Sales and Load, 2026–2045

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2026	131	0.3%	18,481,223	2,421	0.3%	276
2027	131	0.0%	18,473,139	2,420	0.0%	276
2028	132	0.9%	18,395,994	2,431	0.5%	277
2029	133	0.6%	18,439,080	2,452	0.9%	280
2030	134	0.4%	18,629,041	2,489	1.5%	284
2031	135	0.7%	18,610,512	2,505	0.6%	286
2032	136	0.7%	18,583,554	2,520	0.6%	287
2033	137	1.2%	18,458,765	2,532	0.5%	289
2034	138	0.6%	18,479,927	2,550	0.7%	291
2035	138	0.0%	18,656,358	2,575	1.0%	294
2036	139	0.4%	18,692,752	2,591	0.6%	295
2037	139	0.3%	18,755,574	2,607	0.6%	298
2038	140	0.4%	18,785,798	2,622	0.6%	299
2039	141	0.7%	18,778,795	2,640	0.7%	301
2040	141	0.3%	18,858,757	2,659	0.7%	303
2041	142	0.4%	18,937,996	2,681	0.8%	306
2042	142	0.3%	19,040,743	2,704	0.8%	309
2043	142	0.0%	19,206,168	2,727	0.9%	311
2044	143	0.4%	19,300,608	2,752	0.9%	313
2045	144	0.7%	19,391,798	2,784	1.2%	318

Additional Firm Sales and Load***Historical Additional Firm Sales and Load, 2004–2024**

Year	Billed Sales		Average Load (aMW)
	(thousands of MWh)	Percent Change	
2004	1,156		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	906	-6.1%	103
2011	906	0.0%	103
2012	862	-4.9%	98
2013	867	0.6%	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
2019	895	-1.7%	102
2020	900	0.6%	103
2021	912	1.2%	104
2022	947	3.8%	108
2023	1,091	15.3%	125
2024	1,200	9.9%	137

*Includes INL, Lamb Weston, Micron Technology, Simplot Caldwell, and Simplot Pocatello Don Plant; as well as historical off-system customers City of Weiser and Raft River Rural Electric Cooperative, Inc.

Projected Additional Firm Sales and Load, 2026–2045

Year	Billed Sales		Average Load (aMW)
	(thousands of MWh)	Percent Change	
2026	2,257	54.2%	258
2027	4,279	89.6%	488
2028	5,795	35.4%	660
2029	7,016	21.1%	801
2030	7,663	9.2%	875
2031	8,748	14.2%	999
2032	9,309	6.4%	1,060
2033	9,307	0.0%	1,062
2034	9,329	0.2%	1,065
2035	9,332	0.0%	1,065
2036	9,346	0.2%	1,064
2037	9,333	-0.1%	1,065
2038	9,332	0.0%	1,065
2039	9,332	0.0%	1,065
2040	9,346	0.2%	1,064
2041	9,389	0.5%	1,072
2042	9,390	0.0%	1,072
2043	9,390	0.0%	1,072
2044	9,403	0.1%	1,070
2045	9,388	-0.2%	1,072

*Includes Brisbie, LLC (Meta Platforms, Inc.), INL, Lamb Weston, Micron Idaho Semiconductor Manufacturing, Micron Technology, Simplot Caldwell, Simplot Pocatello Don Plant, and other committed large load customers who have entered into procurement or construction agreements with Idaho Power but have not yet executed an ESA.

Appendix A2. Model equations and coefficients

Peak Models

Winter Peak Models

Winter Peak Model Equation:

$$MW_{\text{winter},t} = \beta_1 aMW + \beta_2 \text{HDD65} + \beta_3 \text{Nov} + \beta_4 \text{Dec} + \beta_5 \text{Jan} + \beta_6 \text{Feb} + \beta_7 \text{JAN1516} + \epsilon_t$$

Winter Peak Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	42.24	367.15	0.12	0.91
HDD65	18.66	2.19	8.54	0.00
aMW	0.85	0.25	3.36	0.00
Month_11	-80.68	42.85	-1.88	0.08
Month_12	-286.18	81.35	-3.52	0.00
Month_1	-217.47	74.13	-2.93	0.01
Month_2	-128.35	55.65	-2.31	0.03

Where:

- HDD65 = HDD peak day and HDD basis 65 for forecast period
- MWa = Average monthly demand – without ESA contract contribution
- JAN1516 = January 2015 & 2016 binary
- ϵ_t = Error term

Non-Winter Peak Models

Non-Winter Peak Model Equations:

$$MW_{\text{April},t} = \beta_1 aMW + \beta_2 \text{TEMP} + \beta_3 \text{2001BuyBackBinary} + \beta_4 \text{2008Binary} + \beta_5 \text{2009Binary} + \beta_6 \text{2020OnBinary} + \epsilon_t$$

April Peak Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	731.27	222.35	3.29	0.00
APR_TEMP	6.80	1.18	5.77	0.00
APR_aMW	0.47	0.18	2.62	0.02
APR_Bin2001BuyBack	80.27	55.96	1.43	0.17
APR_Bin2008	247.13	55.37	4.46	0.00
APR_Bin2009	150.11	55.31	2.71	0.01
APR_Bin2020On	98.40	38.03	2.59	0.02

$$MW_{\text{May},t} = \beta_1 aMW + \beta_2 \text{TEMP} + \beta_3 \text{2004Binary} + \beta_4 \text{2005Binary} + \beta_5 \text{2010Binary} + \beta_6 \text{2012Binary} \\ + \beta_7 \text{2020Binary} + \epsilon_t$$

May Peak Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	-672.22	298.79	-2.25	0.04
MAY_TEMP	26.54	2.35	11.31	0.00
MAY_aMW	0.70	0.15	4.82	0.00
MAY_Bin2004	-204.47	75.06	-2.72	0.01
MAY_Bin2005	-482.52	73.81	-6.54	0.00
MAY_Bin2010	-348.27	74.84	-4.65	0.00
MAY_Bin2012	-209.76	73.09	-2.87	0.01
MAY_Bin2020	199.29	76.50	2.61	0.02

$$MW_{\text{July},t} = \beta_1 aMW + \beta_2 \text{TEMP} + \beta_3 \text{Rain} + \beta_4 \text{PKTempTrend} + \epsilon_t$$

July Peak Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	-20722.54	5171.22	-4.01	0.00
JUL_TEMP	32.91	6.05	5.44	0.00
JUL_aMW	0.67	0.25	2.74	0.01
JULRAIN	-3347.17	1529.92	-2.19	0.04
JULPKTEMPTREND	233.81	68.90	3.39	0.00

$$MW_{\text{August},t} = \beta_1 aMW + \beta_2 \text{TEMP} + \beta_3 \text{PKTempTrend} + \epsilon_t$$

August Peak Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	-9544.74	1474.56	-6.47	0.00
AUG_TEMP	28.77	3.91	7.35	0.00
AUG_aMW	0.73	0.17	4.37	0.00
AUGPKTEMPTREND	104.09	21.63	4.81	0.00

$$MW_{\text{September},t} = \beta_1 aMW + \beta_2 \text{TEMP} + \beta_3 \text{2000Binary} + \beta_4 \text{2008Binary} + \beta_5 \text{2017Binary} + \epsilon_t$$

September Peak Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	-2931.45	447.18	-6.56	0.00
SEP_TEMP	33.91	7.03	4.83	0.00
SEP_aMW	1.74	0.23	7.51	0.00
SEP_Bin2000	-270.09	92.79	-2.91	0.01
SEP_Bin2008	-271.86	97.97	-2.77	0.01
SEP_Bin2017	312.25	91.53	3.41	0.00

$$MW_{\text{October},t} = \beta_1 aMW + \beta_2 \text{TEMP} + \beta_3 \text{Rain} + \beta_4 \text{2010OnBinary} + \beta_5 \text{2013OnBinary} + \beta_6 \text{2016Binary} + \beta_7 \text{2019Binary} + \epsilon_t$$

October Peak Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	468.69	269.13	1.74	0.10
OCT_TEMP	3.54	1.22	2.89	0.01
OCT_aMW	0.93	0.20	4.69	0.00
OCT_Bin2010On	117.17	53.07	2.21	0.04
OCT_Bin2013On	-189.06	51.32	-3.68	0.00
OCT_Bin2016	448.95	163.48	2.75	0.01
OCT_Bin2019	212.67	77.39	2.75	0.01
OCT_Rain	-604.28	192.38	-3.14	0.01

The month of June does not have a peak model as the July peak model is also being used to forecast the June peak.

Where:

- aMW = Average monthly demand – without special contracts
- Month_TEMP = Temperature on peak day and temperature for forecast period
- PKTempTrend = Peak temperature trend, used in July & August
- Rain = Four-day sum of weighted precipitation
- ϵ_t = Error term

Class Forecast Models

Residential Class Forecast Model

Residential Model Equation:

$$\text{ResUsePerCust}_t = \beta_1 X_{\text{Heat}}_t + \beta_2 X_{\text{Cool}}_t + \beta_3 X_{\text{Other}}_t + \beta_4 \text{ExtrmWinter}_t + \beta_5 \text{ExtrmHeat}_t + \beta_6 \text{SeasShoulder}_t + \beta_7 \text{LeapYr}_t + \beta_8 \text{ExtrmPrecip}_t + \varepsilon_t$$

Where:

- XHeat = Residential Heating Component (Statistically adjusted end-use (SAE), Actual History with Normal Weather Forecast)
- XCool = Residential Cooling Component (Statistically adjusted end-use (SAE), Actual History with Normal Weather Forecast)
- XOther = Residential Non-HVAC Component (Statistically adjusted end-use (SAE), Actual History with Normal Weather Forecast)
- ExtrmWinter = Binary for January & February 2013, January & February 2017
- ExtrmHeat = Binary for July & August 2021, August & September 2022
- SeasShoulder = Binary for Months of April, May, October, and November
- LeapYr = Binary for February in Leap Years
- ExtrmPrecip = Binary for August 2023
- ε_t = Error term

Residential Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
XHeat	0.957	0.026	37.327	0.00
XCool	0.957	0.031	30.635	0.00
XOther	0.958	0.021	45.725	0.00
ExtrmWinter	95.469	19.450	4.908	0.00
ExtrmHeat	-104.974	21.908	-4.792	0.00
SeasShoulder	-63.992	8.504	-7.525	0.00
LeapYr	14.401	20.835	0.691	49.07
ExtrmPrecip	-91.479	36.948	-2.476	1.46

Commercial Class Forecast Models

Commercial Service Model Equation:

$$MW_{\text{Commercial_SVC},t} = \beta_1 \text{HDD}_t + \beta_2 \text{CDD}_t + \beta_3 \text{GasPrice}_t + \beta_4 \text{Exports}_{t-1} + \beta_5 \text{Wholesale}_t + \varepsilon_t$$

Where:

- HDD = Sum of annual heating degree days base 65 degrees
- CDD = Sum of annual cooling degree days base 65 degrees
- GasPrice = Natural gas price lagged 1 year
- Exports = Total US exports
- Wholesale = Wholesale earnings in IPC service area
- ε_t = Error term

Commercial Service Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	1338049.881	113395.135	11.800	0.00
HDD	59.174	16.272	3.637	0.24
CDD	142.013	40.958	3.467	0.34
GasPrice	111085.926	44028.915	2.523	2.34
Exports	672.909	41.235	16.319	0.00
Wholesale	146.793	25.604	5.733	0.00

Commercial Manufacturing Model Equation:

$$MW_{\text{Commercial_MFG},t} = \beta_1 \text{POP}_t + \beta_2 \text{MFG}_t + \beta_3 \text{GasPrice}_t + \beta_4 (\text{Exports/GDP})_t + (\text{Exports/GDP})_{t-1} + \beta_5 (\text{Comm Price/Ind Price})_t + \varepsilon_t$$

Where:

- POP = Total population of Idaho Power service area
- MFG = Total manufacturing earnings
- GasPrice = Natural gas price
- Exports/GDP = Lag difference of ratio of total US exports / GDP
- Comm Price/Ind Price = Ratio of Commercial electricity price and Industrial electricity price
- ε_t = Error term

Commercial Manufacturing Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	-180836.158	105205.925	-1.719	10.62
POP	1426.890	44.084	32.367	0.00
MFG	29.442	2.985	9.865	0.00
GasPrice	-107666.514	17620.062	-6.11	0.00
Exports/GDP	-721062.150	210529.946	-3.425	0.38
Comm Price/Ind Price	-369057.772	120948.416	-3.051	0.81

Industrial Class Forecast Models

Industrial Service Model Equation:

$$MW_{\text{Industrial_SVC},t} = \beta_1 \text{SVC19}_t + \beta_2 \text{Exports}_t + \beta_3 \text{Education}_t + \beta_4 \text{Households}_t + \text{Households}_{t-1} + \beta_5 (\text{Exports/Trade})_t + (\text{Exports/Trade})_{t-1} + \epsilon_t$$

Where:

- SVC19 = Total number of industrial service customers
- Exports = Total US exports
- Education = Education earnings
- Households = Lag difference of total homes in IPC service area
- Export/Trade = Lag difference of Ratio of total US exports to total trade
- ϵ_t = Error term

Industrial Service Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	246295.871	27915.512	8.823	0.00
SVC19	2248.109	525.897	4.275	0.07
Exports	66.264	6.263	10.58	0.00
Education	81107.664	11011.001	7.366	0.00
Households	1440.732	539.031	2.673	1.74
Export/Trade	-350006.408	133994.388	-2.612	1.96

Industrial Manufacturing Model Equation:

$$MW_{\text{Industrial_MFG},t} = \beta_1 \text{Construction}_t + \beta_2 \text{Exports}_t + \beta_3 \text{GasPrice}_{t-1} + \beta_4 \text{Government}_t + \beta_5 (\text{Exports/Food})_t + \epsilon_t$$

Where:

- Construction = Construction earnings
- Exports = Total U.S. exports
- GasPrice = Natural gas price lagged 1 year
- Government = Government earnings
- Export/Food = Ratio of total exports to food earnings
- ϵ_t = Error term

Industrial Manufacturing Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	213276.711	126357.9	1.688	11.21
Construction	109.716	9.012	12.175	0.00
Exports	130.276	36.079	3.611	0.26
GasPrice	-137290.115	27043.714	-5.077	0.01
Government	169.568	28.608	5.927	0.00
Export/Food	38867.071	16332.615	2.380	3.10

Irrigation Class Forecast Model

Irrigation Model Equation:

$$MW_{\text{Irrigation},t} = \beta_1 \text{IrrCust}_t + \beta_2 \text{WGDD50}_t + \beta_3 \text{SpringPrecip}_t + \beta_4 \text{ResiCust}_t + \epsilon_t$$

Where:

- IrrCust = Annual Maximum Irrigation Customer Count
- WGDD50 = Horsepower-Weighted Growing Degree Days Base 50 Degrees
- SpringPrecip = Horsepower-Weighted Inches of Spring Precipitation
- ResiCust = 4-Year Average of Average Residential Customers Added Per Year
- ϵ_t = Error term

Irrigation Model Coefficients:

Variable	Estimate	Std. Error	t value	Pr(> t)
(Intercept)	1051.834	291.3	3.61	0.23
IrrCust	0.035	0.011	3.08	0.71
WGDD50	0.204	0.107	1.90	7.53
SpringPrecip	-73.365	14.43	-5.09	0.01
ResiCust	-0.01	0.005	-1.98	6.52

