BUILDING OUR FUTURE

September 2023

IRP

INTEGRATED RESOURCE PLAN

APPENDIX A: **SALES & LOAD FORECAST**

IDAHO POWER®

SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2023 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 2024 through 2043.

This appendix describes the development of the anticipated monthly 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 anticipated 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 anticipated case economic/demographic variables by applying historically based parameters of growth on both the low and high side of the economic determinants of the anticipated case forecast.

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 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 said economic data include, but are not limited to, the Idaho Department of Labor, 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 1.6% 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 2.2% 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 anticipated forecast are tested utilizing a probabilistic distribution of normal weather (temperature and precipitation) applied to the weather assumptions in the anticipated case. This provides a comparative range of outcome that isolates long-term sustained weather influences on the forecast.

The anticipated forecast scenario shows Idaho Power's system load increasing to 2,999 average megawatts (aMW) by 2043 from 2,024 aMW in 2024, representing an average yearly growth rate of 2.1% over the 20-year planning period (2024–2043). A similar annual average growth rate in system load is reflected in various weather-related scenarios. From an annual peak-hour demand perspective, the anticipated case of the peak-demand forecast will grow to 5,337 megawatts (MW) in 2043 from the all-time system peak of 3,751 MW that occurred on Wednesday, June 30, 2021, at 7 p.m. Idaho Power's system peak increases at an average growth rate of 1.8% per year over the 20-year planning period (2024–2043) under this case. Over this same term, the number of Idaho Power active retail customers is expected to increase from the December 2022 level of 616,857 customers to over 855,000 customers by year-end 2043.

Beyond the weather, climate, economic and demographic assumptions used to drive the anticipated 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 2022 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 impact of their energy reduction or addition in the long-term sales and load forecast. Further discussion of these assumptions is presented in each respective section.

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. 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.

2023 IRP SALES AND LOAD FORECAST

Average Load

The economic and demographic variables driving the 2023 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 post Great Recession history. From that point, the global pandemic recession in 2020 had profound effects across the national and global economy. For the company, residential sales increased approximately 5% in 2020 and into 2021. This growth was attributable to both work-from-home edicts as well as continued strong in-migration trends. In the second half of 2022 and into 2023, migration trends have slowed relative to previous years. However, net migration growth into the service area remains positive and more consistent with long-term trends. Negative energy use was initially exhibited by the commercial and industrial classes but has since stabilized and, overall, rebounded quickly. Irrigation sales were mostly unaffected by the pandemic and continue to follow the expected growth trend. Overall, it is assumed economic conditions will return to long-term fundamentals during the 2023 IRP forecast term. Additional significant factors and considerations that influenced the outcome of the 2023 IRP load forecast include the following:

- Weather plays a primary role in impacting the load forecast on a monthly and seasonal basis. In the anticipated 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 2023 IRP reflects a softened expansionary economy in Idaho over the near term and reversion to the long-term trend of the service area economy. While Idaho had the highest residential population growth rate of any state in the nation for the 5 years ending 2020, customer growth and residential permit issuances have come down from those highs in 2022. However, net migration and business investment continues to result in positive economic activity.

- 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 (UPC) over much of the forecast period.

- New industrial and Energy Service Agreement (ESA) customer requests are inherently uncertain regarding location and capacity needs. The anticipated load forecast reflects only those industrial customers that have made a sufficient and significant binding investment and/or interest indicating a commitment of the highest probability of locating in 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 anticipated sales and load forecast.
- The electricity price forecast used to prepare the sales and load forecast in the 2023 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2021 IRP preferred portfolio. Retail electricity prices throughout the planning period can impact the sales forecast, a consequence of the 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, 70th, 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 the forthcoming sections.

The peak forecast results and comparisons with previous forecasts differ for many reasons, including the following:

- The all-time system summer peak demand was 3,751 MW, recorded Wednesday, June 30, 2021, at 7 p.m. The previous all-time system summer peak demand, adjusted for demand response, was 3,437 MW, recorded Friday, July 2, 2013, at 5 p.m. Idaho Power's winter peak-hour load record is 2,604 MW, recorded December 22, 2022, at 9 a.m. The previous winter peak-hour load record was 2,527 MW, realized December 10, 2009, at 8 a.m., and matched January 6, 2017, at 9 a.m.
- The peak model develops peak-scenario impacts based on historical probabilities of peak day temperatures at the 50th, 70th, 90th, and 95th-percentiles of occurrence for each month of the year. These average peak-day temperature drivers are calculated over the 1993 to 2022 period (the most recent 30 years).

- The 2023 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 ESA customers. In conjunction with this load (or sales) forecast, an hourly 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 anticipated 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 50th-percentile average load forecast assumes average temperatures and precipitation (i.e., there is a 50% chance loads will be higher or lower than the anticipated load forecast due to colder-than-normal or hotter-than-normal temperatures and wetter-than-normal or drier-than-normal precipitation). However, the 30-year climatology has been increasing over the past several decades, implying a cold bias in the calculation. Since actual loads can vary significantly depending on weather conditions, alternative scenarios were developed to address load variability due to variable weather—the 70th- and 90th-percentile load forecasts. The 70th-percentile weather was utilized in the anticipated case to adjust for any systemic historic changes.

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

For example, the median HDD in December from 1993 to 2022 (the most recent 30 years) was 1,020 at the Boise Weather Service office. The 70th-percentile HDD is 1,048 and would be exceeded in 3 out of 10 years. The 90th-percentile HDD is 1,126 and would be exceeded in 1 out of 10 years. As an example, for a single month, the near 100th-percentile HDD (the coldest December over the 30 years) is 1,284, which occurred in December 2016. 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 multiple 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 2023 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
Anticipated Case	70%	3 in 10 years	HDD, CDD, GDD, precipitation
50th Percentile	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
70th Percentile	70%	3 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	2024	2028	2033	2043	Annual Growth Rate 2024–2043
90th Percentile	2,087	2,627	2,854	3,076	2.1%
Anticipated Case	2,024	2,561	2,784	2,999	2.1%
50th Percentile	1,974	2,507	2,727	2,936	2.1%

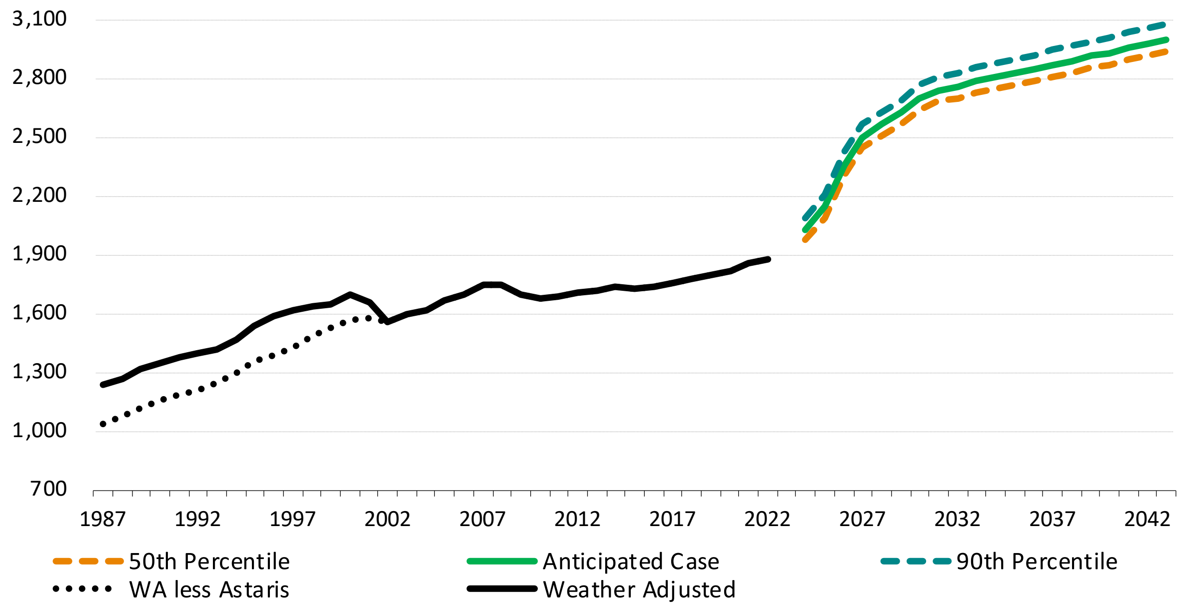


Figure 1. **Forecast system load (aMW)**[1]

Load Forecasts Based on Economic Uncertainty

The anticipated 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 anticipated case forecast. The forecasts provide a range of possible load growth rates for the 2024 to 2043 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 (1998–2022).

Of the three scenarios 1) the anticipated forecast is the median growth path, 2) the standard deviation observed during the historical time is used to estimate the dispersion around the anticipated scenario, and 3) the variation in growth rates will be equivalent to the variation in growth rates observed over the past 25 years (1998–2022).

[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 energy service agreement between Astaris and Idaho Power was terminated.

From the above methodology, two views of probable outcomes form the forecast scenarios—the probability of exceeding and the probability of occurrence—were developed and are reported 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% 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% 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% 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%
Anticipated 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%
Anticipated 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 ESA customers (including past sales to Astaris, Inc. [aka FMC]) and on-system contracts (including past sales to Raft River Coop and the City of Weiser).

Results of Idaho Power's economic scenario probabilistic system load projections are reported in Table 4 and shown in Figure 2. The anticipated system load-forecast growth rate averages 2.1% per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 1.9% per year throughout the forecast period. The high scenario projects a load growth of 2.4% 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% of the probable outcomes as measured by Idaho Power's historical experience.

Table 4. System load growth (aMW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
Low	1,950	2,455	2,630	2,769	1.9%
Anticipated	2,024	2,561	2,784	2,999	2.1%
High	2,066	2,664	2,930	3,224	2.4%

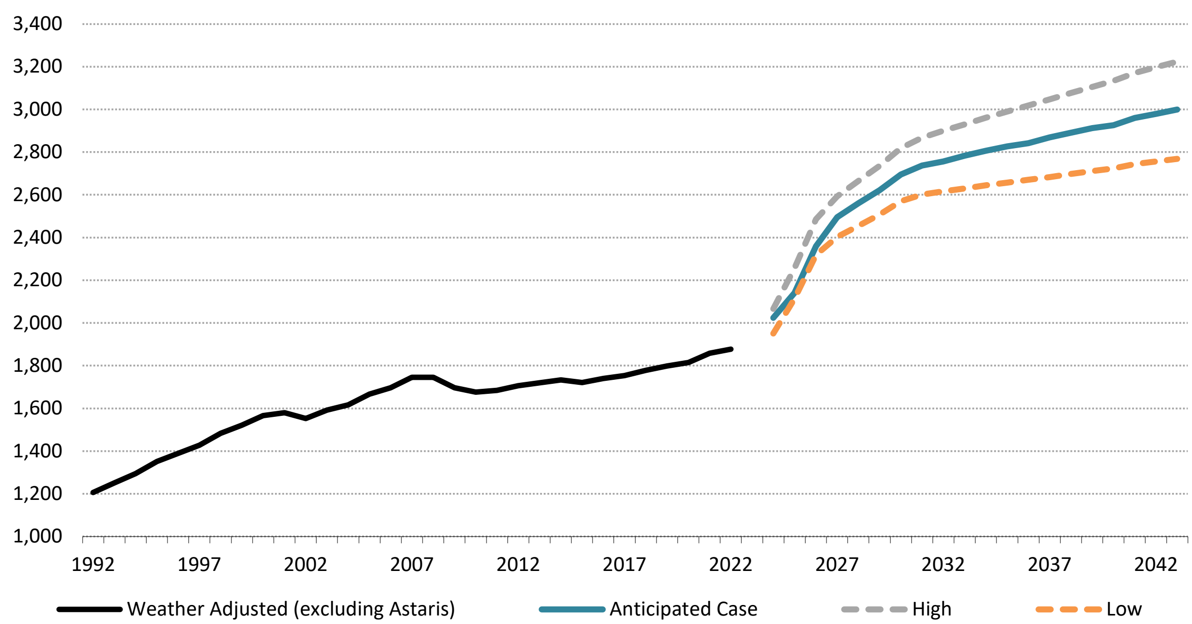


Figure 2. Forecast system load (aMW)

COMPANY SYSTEM LOAD

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as ESA customers (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 anticipated 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 load growth of the anticipated system forecast averages 2.1% per year from 2024 to 2043. Company system load projections are reported in Table 2 and shown in Figure 1.

In the 70th-percentile (anticipated) forecast, the company system load is expected to increase from 2,024 aMW in 2024 to 2,999 aMW in 2043, an average annual growth rate of 2.1%. In the weather sensitive scenarios, the 50th-percentile and 90th-percentile forecasts, the company system load is expected to increase from 1,974 aMW in 2024 to 2,936 aMW by 2043 and increase from 2,087 aMW in 2024 to 3,076 aMW, respectively. All scenarios have an average growth rate of 2.1% per year over the planning period. In the economic probability scenarios, the company system load is expected to increase in the low case from 1,950 aMW in 2024 to 2,769 aMW in 2043, an average annual growth rate of 1.9% and in the high case from 2,066 aMW to 3,224 aMW, an average annual growth rate of 2.4% (Table 4).

The system load, excluding Astaris (formerly known as FMC), portrays the current underlying general business growth trend within the service area. However, the system load with Astaris is instructive regarding the impact of a loss or gain of a significant large-load customer on system load.

Accompanied by the outlook of economic growth for Idaho Power's service area throughout the forecast period, continued growth in Idaho Power's system load is expected. Total load is made up of system load plus long-term, firm, off-system contracts. Currently, 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 22% higher in 2043, gaining 1.2 million megawatt hours (MWh) over 2024. Industrial sales are expected to be 28% higher, or 0.8 million MWh, followed by commercial (17% higher, or 0.7 million additional MWh) and irrigation (12% higher in 2043 than 2024). Additional firm sales are expected to more than quadruple by 2043, gaining 5 million MWh over 2024.

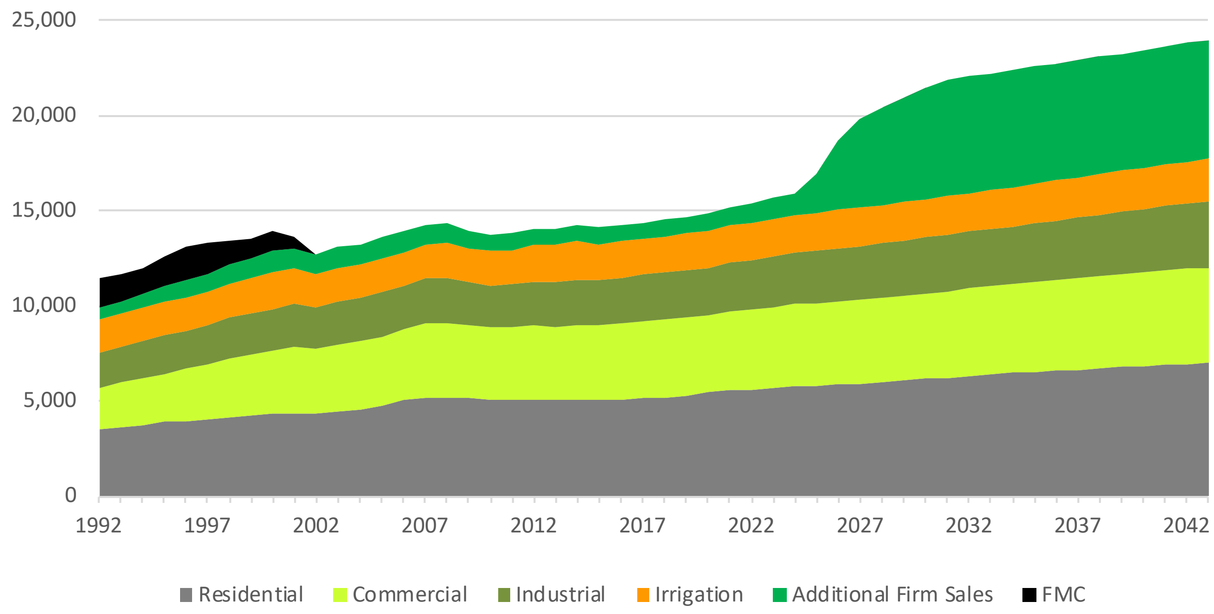


Figure 3. **Composition of system company electricity sales (thousands of MWh)**

Additional Scenarios Developed

In addition to the anticipated sales forecast, differing weather probability cases, and high and low economic cases, alternative sales and load cases were developed for analysis within the 2023 IRP. These scenarios included load flattening, high penetration future of building and transportation electrification, and the addition of approximately 100 MW or 200 MW of capacity requirements to the load forecast due to high growth within the commercial and industrial classes. These additional scenarios are discussed in the following.

Load Flattening

A scenario was generated in which the peak hours of the residential class were reduced, and the load shifted from the peak to the lowest load times of the day to fill in the load valleys. The objective of the load flattening scenario is not associated with a particular technology or policy, but rather is an exercise to test the resource portfolios.

The peak and valley hours for both summer and winter were identified by observing the hourly and seasonal trends of the residential class. A reduction of 10% was subtracted from each hour of the peaks and added to the valleys.

The summer peak is defined as the hours of 5 to 10 p.m. for the months of May through September. The summer demand was shifted to the hours of 3 to 8 a.m. the following day. The winter season is November through March and has both morning and evening peaks. These are defined as the hours of 7 to 10 a.m. and 6 to 10 p.m., respectively. The morning winter peak was moved to the subsequent valley of 1 to 4 p.m., and the evening peak was shifted to 1 to 4 a.m. the following day.

Electrification Scenarios

Rapid electrification scenarios were generated for the IRP to inform Idaho Power of system load requirements should rapid and extensive electrification occur in Idaho Power's service area. Rapid electrification includes assumptions around both transportation and building electrification, which includes light-duty electric vehicles; residential heat pump water heaters; and residential air source (and ground source) heat pumps. These are discussed in detail below. It is important to note this does not represent an electrification path that is most likely, rather more on the far tails of electrification possibilities. The objective of the electrification scenario is not associated with a probable outcome but rather is an exercise to test the resource portfolios.

For the building electrification assumptions, current equipment saturations specified from Idaho Power's 2022 end-use study were identified and ramped up to an 80% saturation by the end of the planning period. These saturations are calibrated to Idaho Power's customer forecast to understand the number of units that would be on the system and thus the amount of energy required for the newly installed equipment. Those equipment saturations were cross-referenced to equipment usage specifications from Applied Energy Group's (AEG) LoadMAP models used in Idaho Power's 2022 energy efficiency potential study. Further, the newly installed units were assumed to be the most efficient equipment known today. The product of the saturations and resulting equipment annual usage was shaped to understand the hourly impacts over the planning period. Load shapes were taken from the Northwest Regional Technical Forum (RTF).

For transportation electrification, the electric vehicle adoption assumption was relaxed from the most probable outcome, as included in the base forecast used in the 2023 IRP, to reach a saturation level of 93% at the end of the planning period. The electric vehicle load shape was obtained from the RTF, which was modified from an Avista Utilities Electric Vehicle Supply Equipment (EVSE) study. The goal was to shift the primary amount of required load away from the typical summer peak hours into the late evening, as well as the late morning. During this process, it was also assumed workplace charging became more common.

In these scenarios, all electric vehicles and conversions of space/water heating from natural gas to electricity were load building. All electric resistance space/water heating and currently installed heat pumps and air conditioners were converted to more efficient heat pumps and reduced system load.

Idaho Power will continue to monitor electric vehicle registrations from the Idaho Department of Transportation, as well as update end-use studies every few years, to assess if a similar rapid and extensive electrification scenario is being entered into as modeled.

High Growth Scenarios

Additional scenarios were run for high-growth futures in the Idaho Power service area. There have been numerous requests to Idaho Power for development of large commercial and industrial projects over the course of 2022 and 2023. These scenarios were developed to capture the potential of one of these projects moving forward and assess resource adequacy and cost. The first scenario represents a single or aggregate 100 MW added on to Idaho Power's system over the course of year 2026. The second scenario represents a single or aggregate 200 MW added on to Idaho Power's system, ramping up over the years 2026–2027.

COMPANY SYSTEM PEAK

System peak load includes the sum of the coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as ESA customers (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 3,751 MW, recorded on Wednesday, June 30, 2021, at 7 p.m. The previous all-time system summer peak demand, adjusted for demand response, was 3,437 MW, recorded on Friday, July 2, 2013, at 5 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 became standard in nearly all new residential homes and new commercial buildings.

In the 95th-percentile forecast, the system summer peak load is expected to increase from 3,920 MW in 2024 to 5,427 MW in 2043. In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,894 MW in 2024 to 5,401 MW in 2043. In the 70th-percentile forecast, or anticipated case, the system summer peak load is expected to increase from 3,830 MW in 2024 to 5,337 MW in 2043. Finally, in the 50th-percentile forecast, the system summer peak load increases from 3,767 MW in 2024 to 5,274 MW in 2043. The 95th- and 90th-percentile forecasts represent an average summer peak growth rate of 1.7% per year over the planning period. The 70th- and 50th-percentile forecasts represent an average summer peak growth rate of 1.8% per year over the planning period (Table 5).

Table 5. System summer peak load growth (MW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
95th Percentile	3,920	4,592	4,937	5,427	1.7%
90th Percentile	3,894	4,565	4,911	5,401	1.7%
70th Percentile	3,830	4,501	4,847	5,337	1.8%
50th Percentile	3,767	4,439	4,784	5,274	1.8%

The four 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% curtailment in irrigation load due to a voluntary load reduction program.

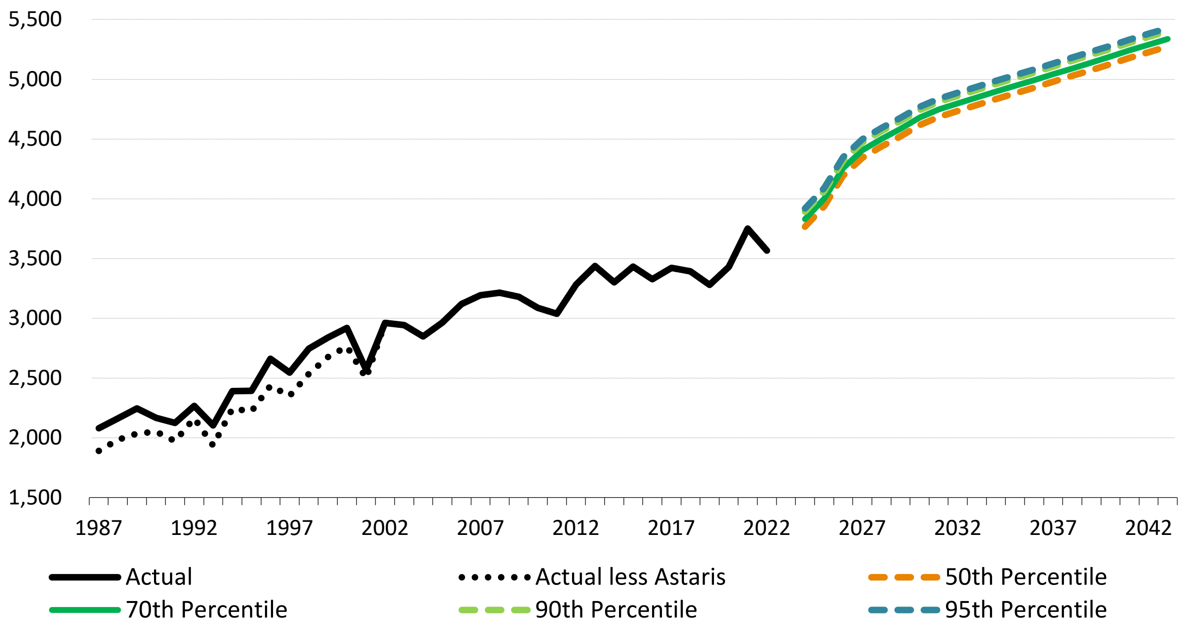


Figure 4. Forecast system summer peak (MW)

The all-time system winter peak demand was 2,604 MW, recorded Thursday, December 22, 2022, at 9 a.m. The previous all-time system winter peak demand was 2,527 MW, realized Thursday, December 10, 2009, at 8 a.m. and matched January 6, 2017, at 9 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 greater 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 2,750 MW in 2024 to 3,593 MW in 2043, an average growth rate of 1.4% per year over the planning period. In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,647 MW in 2024 to 3,557 MW in 2043, an average growth rate of 1.6% per year over the planning period. In the 70th-percentile forecast, or anticipated case, the system winter peak is expected to increase from 2,567 MW in 2024 to 3,477 MW in 2043, an average growth rate of 1.6% per year over the planning period. In the 50th-percentile forecast, the system winter peak load is expected to increase from 2,512 MW in 2024 to 3,422 MW in 2043, an average growth rate of 1.6% per year over the planning period. This data is represented in Table 6. The four scenarios of projected system winter peak load are illustrated in Figure 5.[2]

Table 6. System winter peak load growth (MW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
95th Percentile	2,750	3,269	3,441	3,593	1.4%
90th Percentile	2,647	3,165	3,379	3,557	1.6%
70th Percentile	2,567	3,085	3,299	3,477	1.6%
50th Percentile	2,512	3,029	3,243	3,422	1.6%

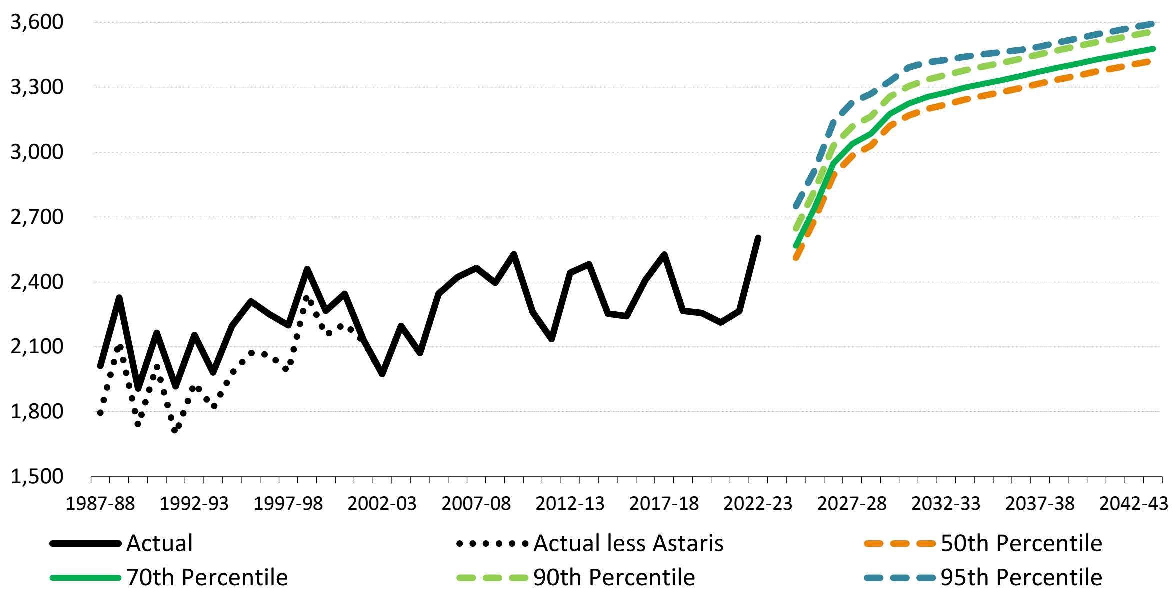


Figure 5. Forecast system winter peak (MW)

The historic relationship of summer and winter peaks is depicted in Figure 6. The growth in the summer peak over the past several decades in Idaho Power's service territory, as evidenced by

[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% 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 1993 to 2022 period (the most recent 30 years).

the shift in the most-recent slope lines, has been significantly greater due to the increased presence of urban cooling load in the peak summer months.

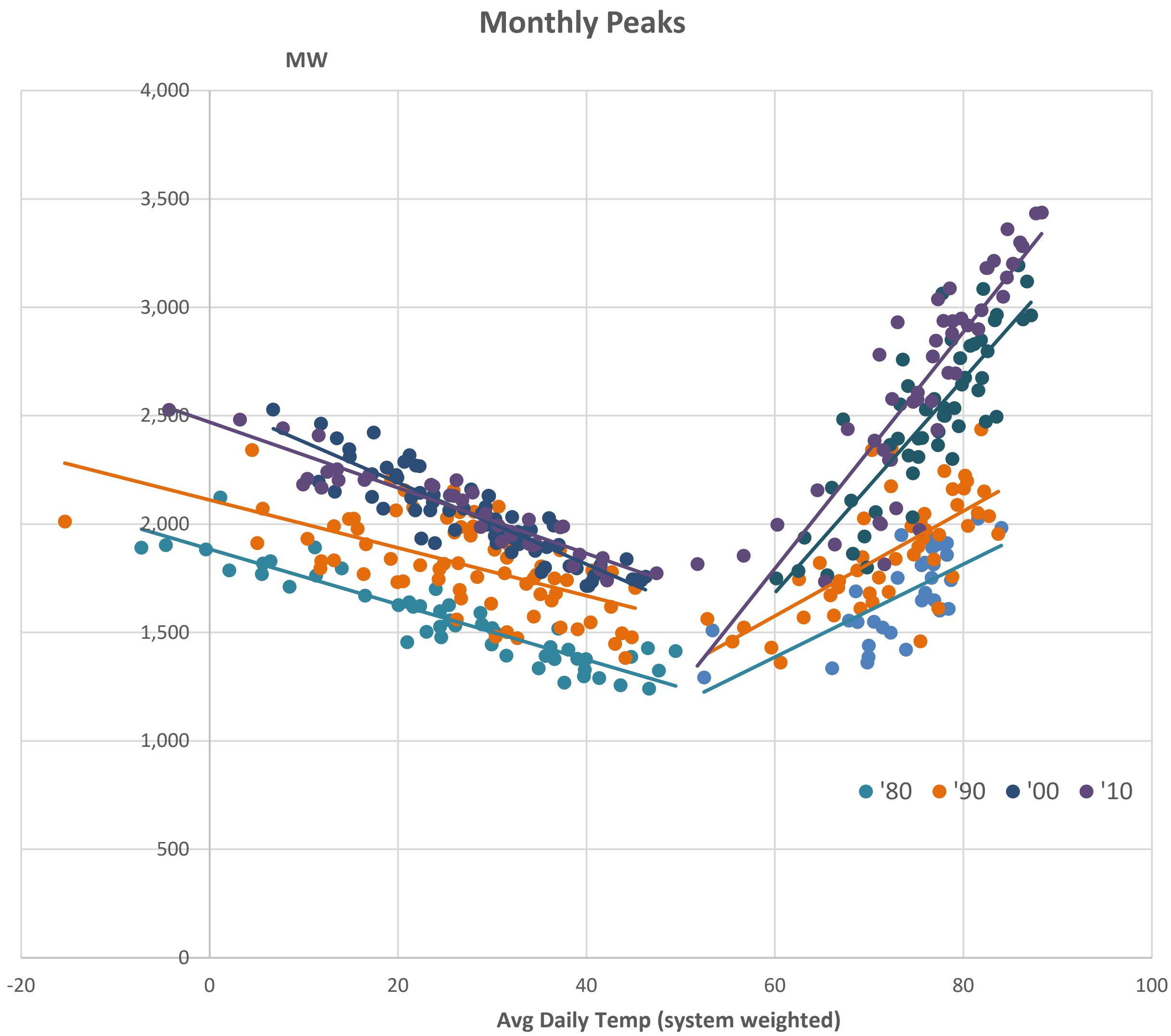


Figure 6. Idaho Power monthly peaks (MW)

Note the 2023 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.

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 over 20 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, 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-day temperatures is a key driver of the monthly system peak models. The normal average peak-day temperature drivers are calculated over the 1993 to 2022 period (the most recent 30 years). In addition, the peak model develops peak scenarios based on historical probabilities of peak day temperatures at the 50^{th}, 70^{th}, 90^{th}, and 95^{th} percentiles of occurrence for each month of the year.

Note the summertime (June through September) 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 2043, the end of the forecast period. 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 FORECAST

Residential

The 70th-percentile (anticipated) residential load is forecast to increase from 678 aMW in 2024 to 830 aMW in 2043, an average annual compound growth rate of 1.1%. In the 50th-percentile scenario, the residential load is forecast to increase from 655 aMW in 2024 to 799 aMW in 2043 at an average annual compound growth rate of 1.1%, matching the anticipated residential growth rate. The 90th-percentile residential load is forecast to increase from 707 aMW in 2024 to 870 aMW in 2043, also at an average annual compound growth rate of 1.1%. The residential load forecasts are reported in Table 7 and shown in Figure 7.

Table 7. Residential load growth (aMW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
90th Percentile	707	740	793	870	1.1%
Anticipated Case	678	708	758	830	1.1%
50th Percentile	655	683	731	799	1.1%

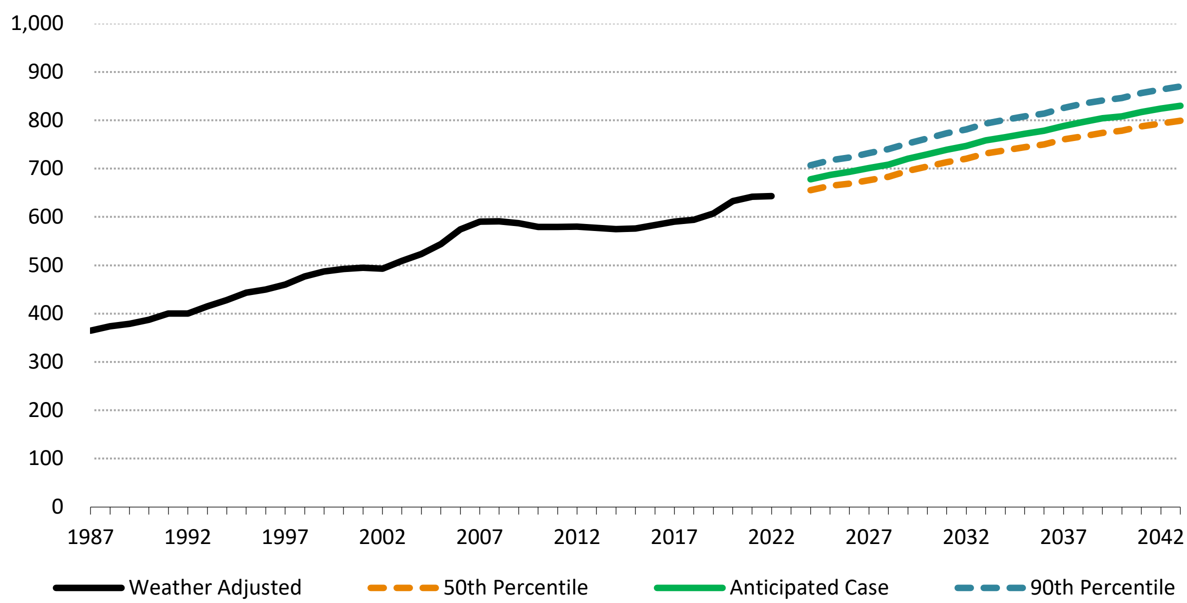


Figure 7. Forecast residential load (aMW)

Sales to residential customers made up 31% of Idaho Power's system sales in 1992 and 37% of system sales in 2022. The number of residential customers is projected to increase to nearly 724,000 by December 2043.

The average sales per residential customer increased to nearly 14,800 kilowatt-hours (kWh) in 1980 before declining to 13,200 kWh in 2001. In 2002, residential UPC dropped dramatically—over 500 kWh per customer from 2001—the result of significantly higher electricity prices combined with a weak national and service area economy. The reduction in electricity prices in June 2003 and a recovery in the service-area economy caused residential UPC to stabilize through 2007. However, conservation efforts have placed downward pressure on residential UPC since that point. This trend is expected to continue, declining at 0.6% annually over the 2024–2043 planning period, as total residential UPC is expected to decrease to approximately 9,700 kWh by 2043. Residential UPC is shown in Figure 8.

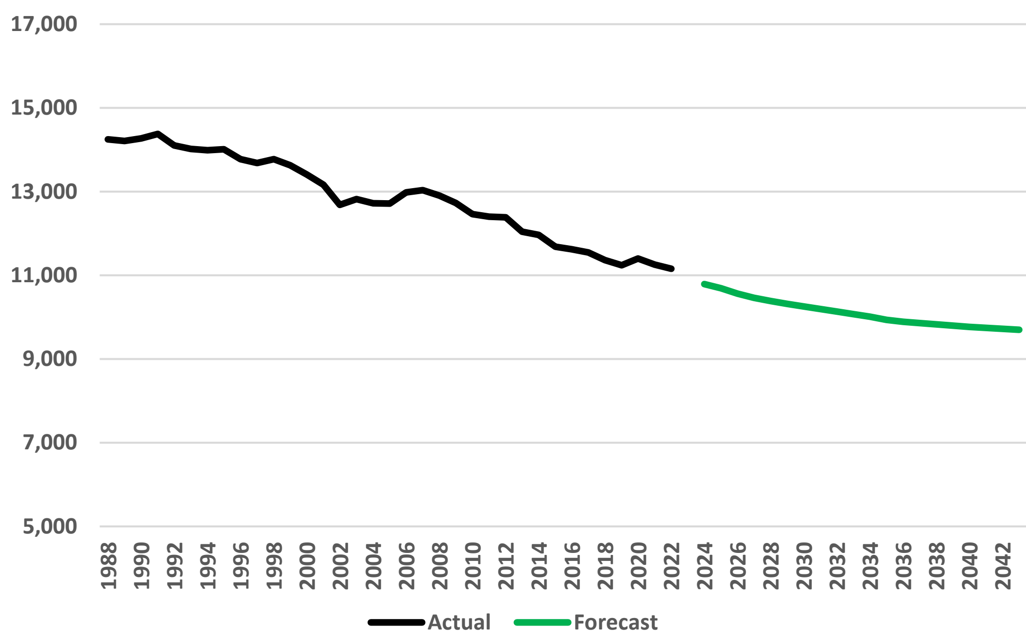


Figure 8. Forecast residential UPC (weather-adjusted kWh)

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 2024 to 2043 shows an average annual compound growth rate of 1.6% as shown in Figure 9.

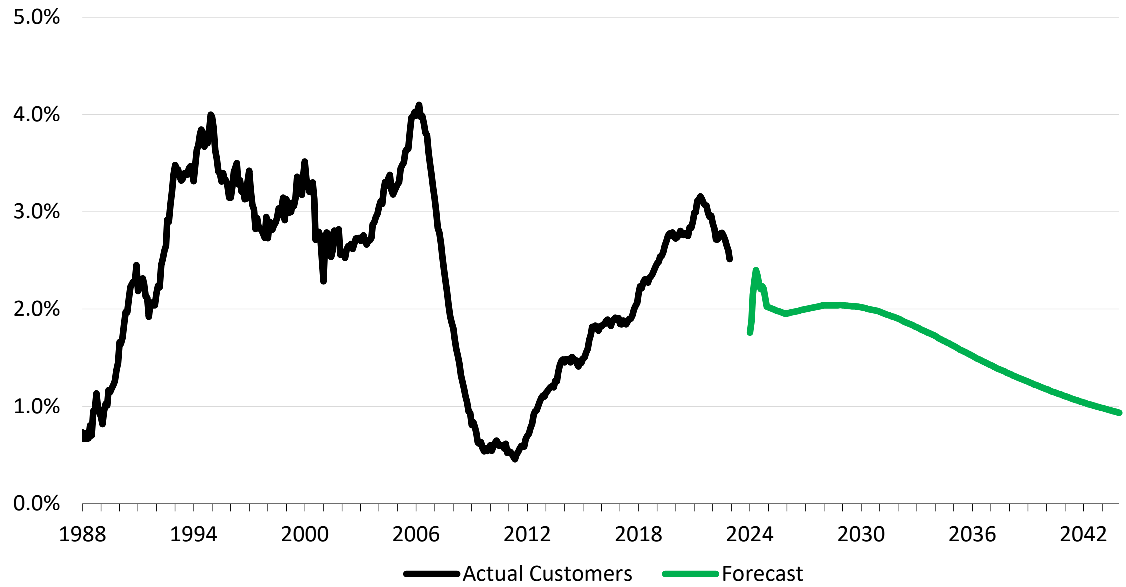


Figure 9. Residential customer growth rates (12-month change)

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.

A general schematic of the forecasting methodology using a statistically adjusted end-use (SAE) forecast model as described above that is used in Idaho Power's forecast residential sales is provided in Figure 10.

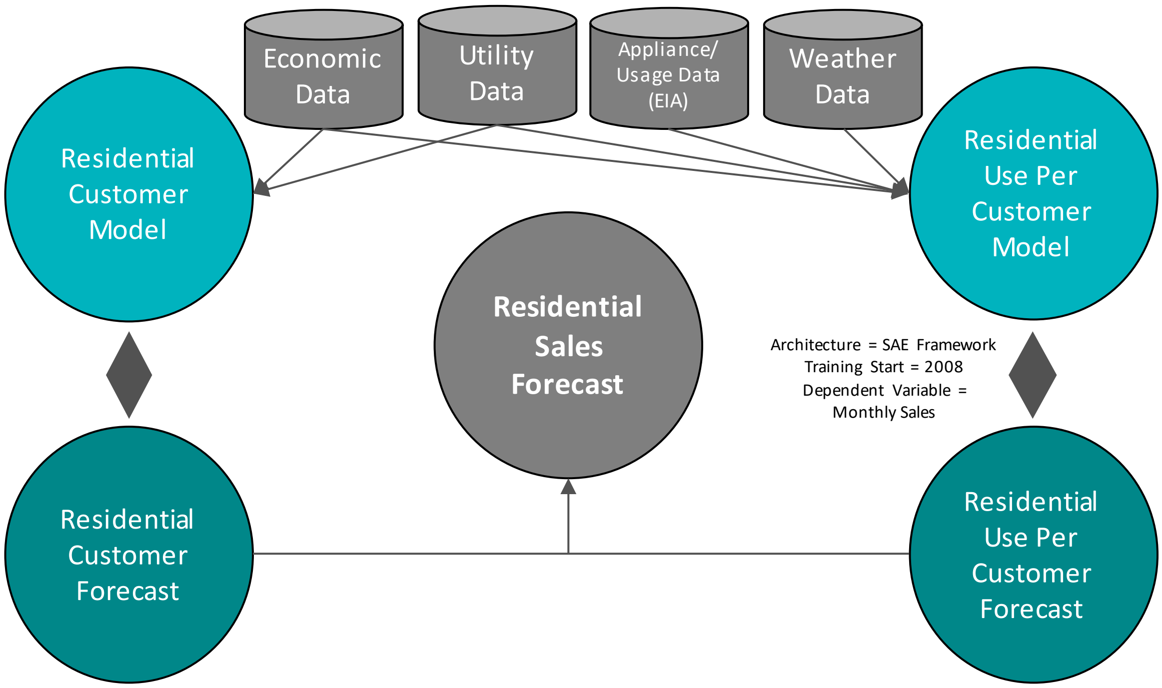


Figure 10. Residential sales forecast methodology framework

There were several instances in the SAE framework where the overall outcomes could benefit from the inclusion of indicator variables. In assessing these and combination thereof, Idaho Power selected the best statistical result across a menu of options using cross validation methods.

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 70th-percentile (anticipated case) scenario, commercial load is projected to increase from 500 aMW in 2024 to 586 aMW in 2043 (Table 8). The average annual compound growth rate of the commercial load in the anticipated scenario is 0.8% during the forecast period. The commercial load in the 50th-percentile scenario is projected to increase from 492 aMW in 2024 to 576 aMW in 2043, also at an average annual compound growth rate of 0.8%. The commercial load in the 90th-percentile scenario is projected to increase from 509 aMW in 2024 to 599 aMW in 2043, an average annual compound growth rate of 0.9%. The commercial load forecast scenarios are illustrated in Figure 11.

Table 8. Commercial load growth (aMW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
90th Percentile	509	524	548	599	0.9%
Anticipated Case	500	515	537	586	0.8%
50th Percentile	492	506	528	576	0.8%

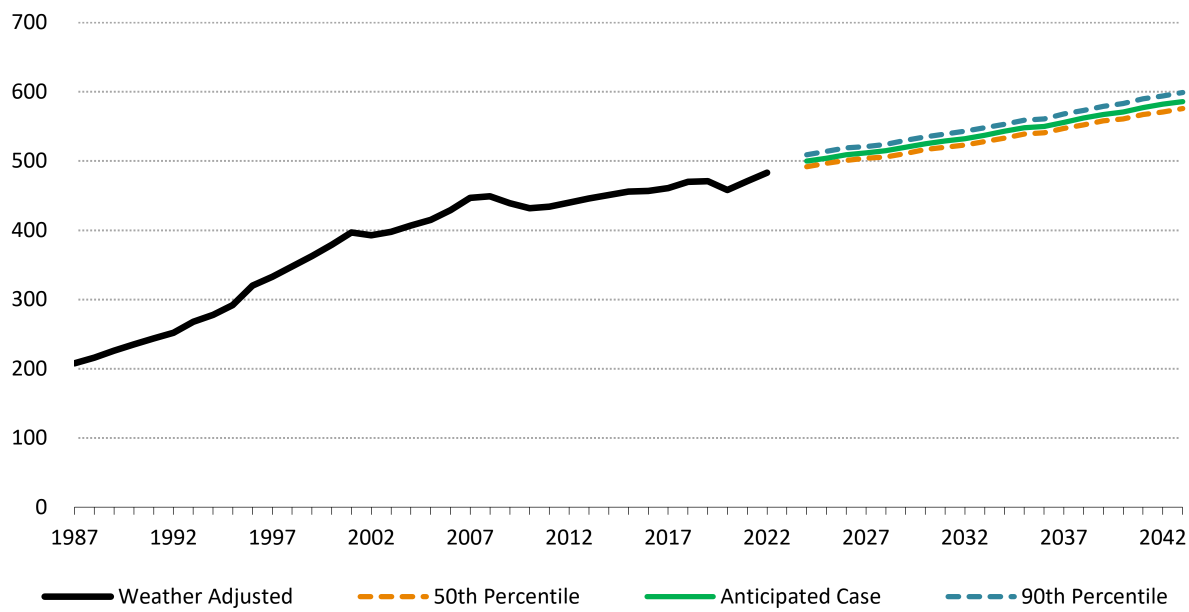


Figure 11. Forecast commercial load (aMW)

With a customer base of over 77,300, 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—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 12 shows the breakdown of the categories and their relative sizes based on 2022 billed energy sales.

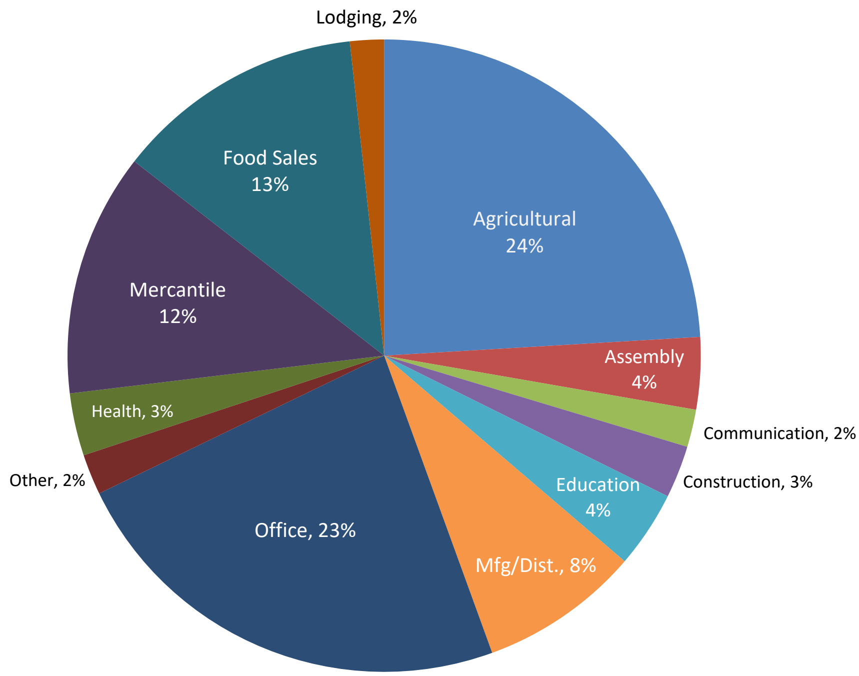


Figure 12. Commercial building share—energy use

As indicated in Figure 12, agricultural-related and office-oriented operations represent approximately 50% of the commercial sector. The mercantile group continues a contraction trend due to consolidation and online/home delivery substitution, with substitutive growth coming to manufacturing/distribution. Growth continues within the construction group, albeit slowing in the most recent period as new single-housing unit share has diminished in favor of multi-family housing as well as inventory overhang within the market. The health and education group consolidation that had previously exhibited contraction in share and growth rates has diminished and stabilized as of the last IRP. As referenced above, the online share of the supply chain has resulted in continued growth in warehouse and distribution customers, reflected in the manufacturing/distribution group. Agricultural and manufacturing operations continue to migrate to the service territory and flourish with average long-term growth rates of 1.6% and 2.9%, respectively.

The number of commercial customers is expected to increase at an average annual rate of 1.5%, reaching approximately 105,200 customers by December 2043. In 1992, customers in the commercial category consumed approximately 19% of Idaho Power system sales, growing to 27% by 2022.

Figure 13 shows historical and forecast average UPC for the entire category. The commercial UPC metric in Figure 13 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 peaked in 2001 at 67,800 kWh and has declined at approximately 1% compounded annually to 2022. The UPC is forecast to decrease at an annual rate of 0.7% 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.

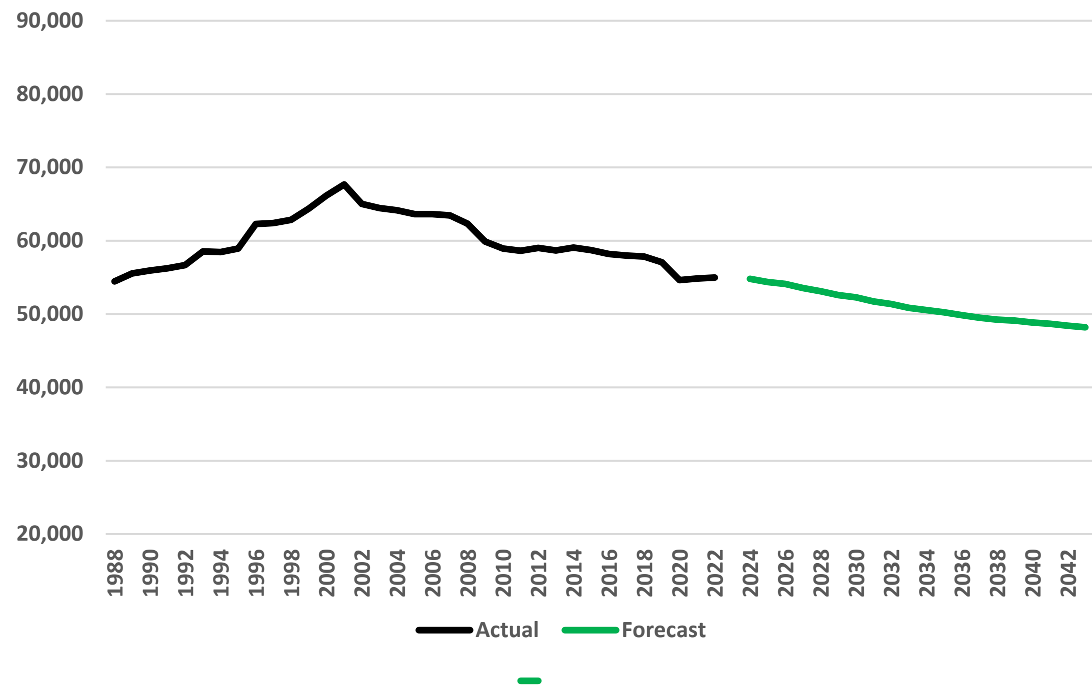


Figure 13. **Forecast commercial UPC (weather-adjusted kWh)**

Figure 14 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2022 UPC for each segment relative to the 2016 UPC. A value greater than 100% 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.

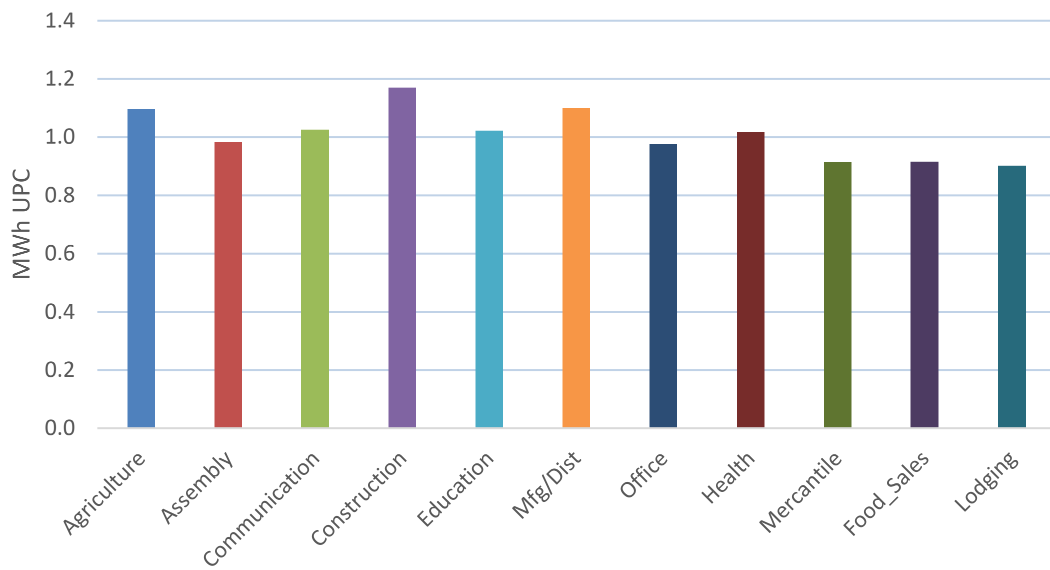


Figure 14. Commercial categories UPC, 2022 relative to 2016

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, however manufacturing motors are significant for that sector. Understandably, aggressive DSM measures can reduce a customer's usage to trigger a rate-class change from industrial to commercial class. These shifts are evident in the chart with the most aggressive DSM implementation categories of Education and Food Sales. 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. Tariff migration occurs at the boundary of Schedule 9P (large primary commercial) and Schedule 19 (large industrial). Note the forecast models aggregate the energy use of these two schedules to mitigate this influence.

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.

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 2022, the number of industrial customers had risen to 125, representing approximately 17% of system sales. As mentioned earlier in the commercial discussion, customer counts in this tariff class are impacted by migration to and from the commercial class as dictated by tariff rules. However, 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 ESA customers and are addressed in the Additional Firm Load section of this document.

In the anticipated forecast, industrial load grows from 311 aMW in 2024 to 400 aMW in 2043, an average annual growth rate of 1.3% (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 50th- and 90th-percentile weather scenarios are identical to the anticipated industrial load scenario. The industrial load forecast is pictured in Figure 15.

Table 9. Industrial load growth (aMW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
Anticipated Case	311	326	346	400	1.3%

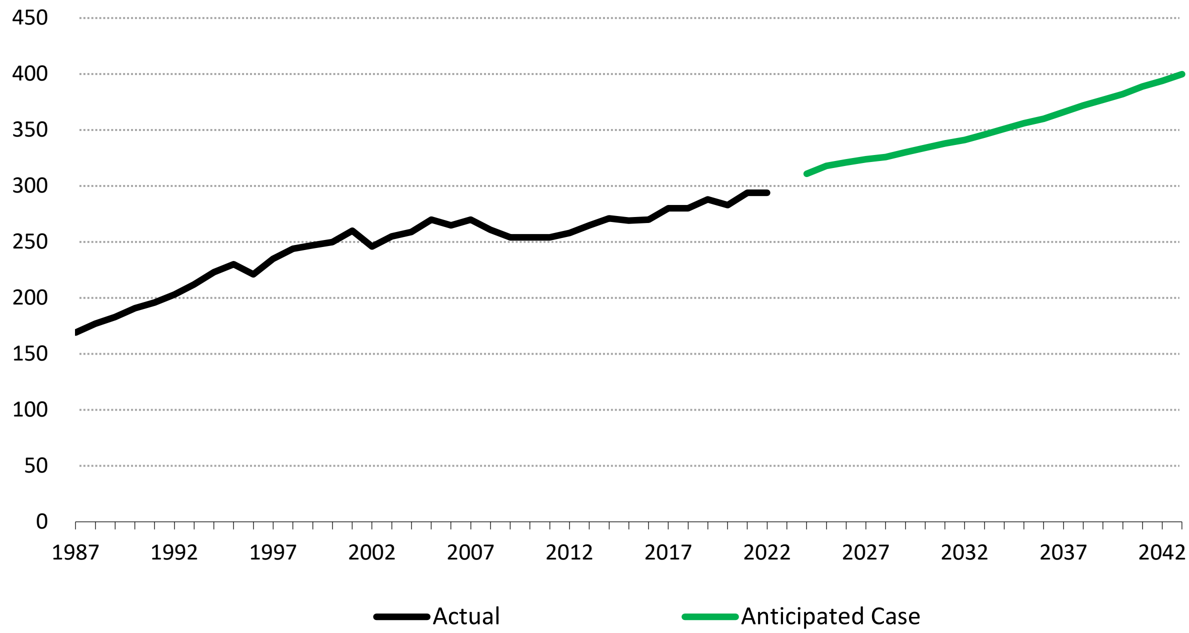


Figure 15. Forecast industrial load (aMW)

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 are provided by the DSM specialists within Idaho Power. The economic and other independent (causal) 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 2022 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 (39%), followed by dairy (19%) and construction-related (7%). The categorization scheme includes a range of service-providing 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.

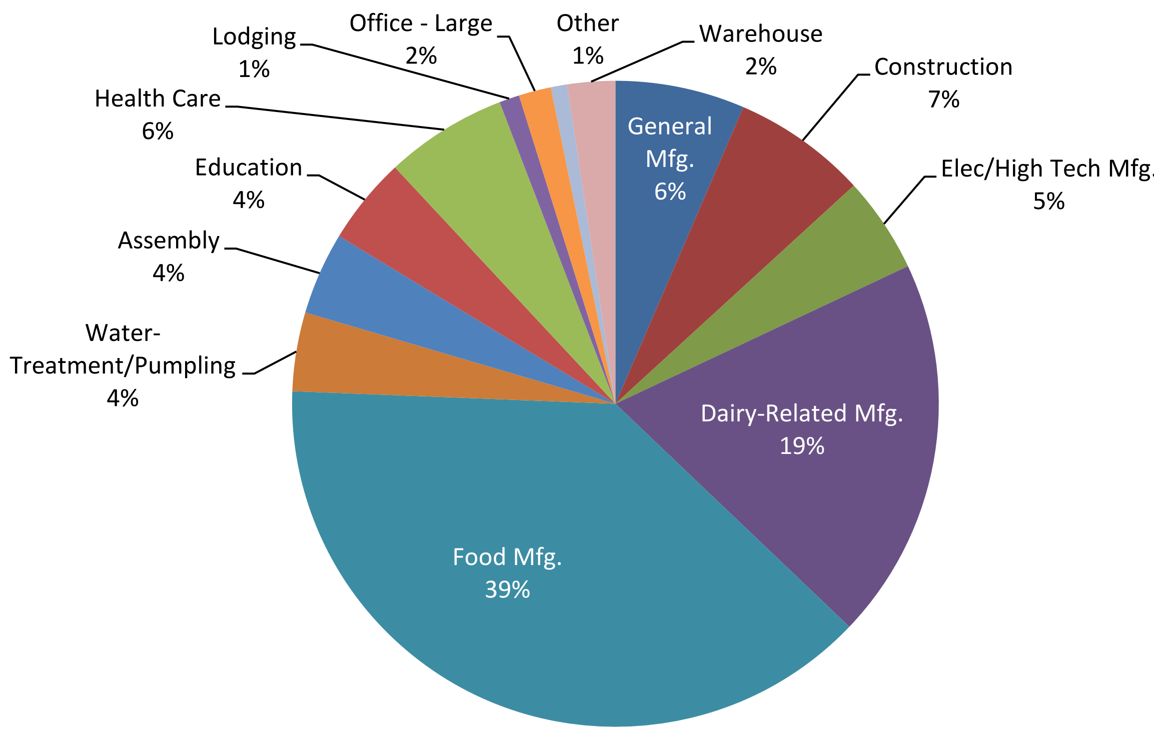


Figure 16. Industrial electricity consumption by industry group (based on 2022 sales)

The regression models and associated explanatory variables resulting from the categorization establish the relationship between historical electricity sales and variables such as, corporate earnings, 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 previously excluded DSM is subtracted. Figure 17 shows the general forecasting methodology used for both the commercial and industrial sectors.

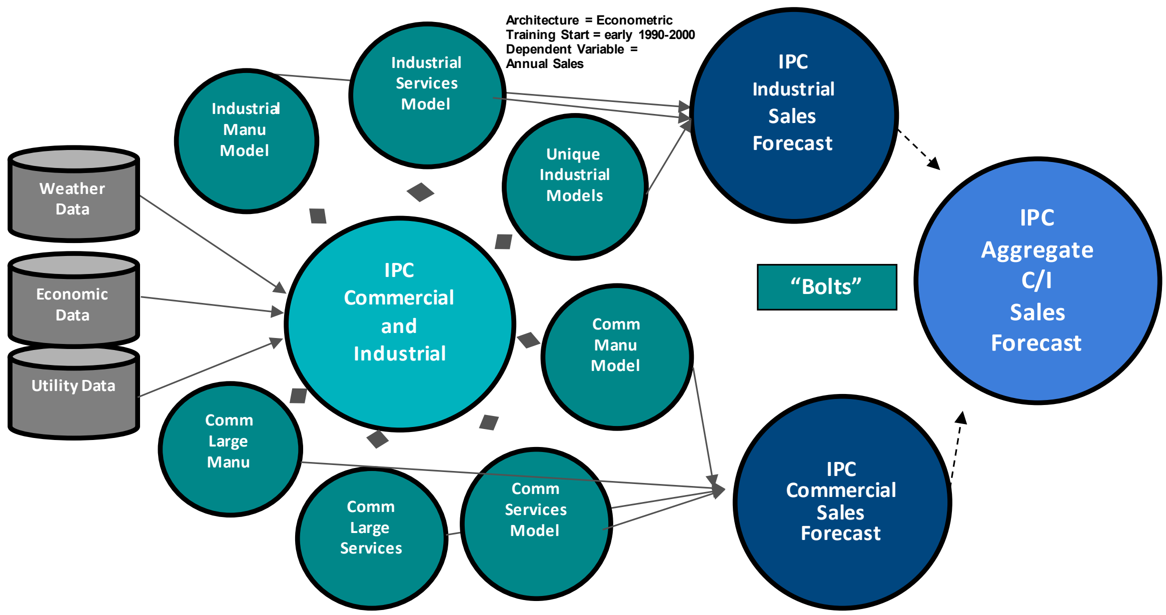


Figure 17. Commercial and industrial sales forecast methodology

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 70th-percentile (anticipated) irrigation load is forecast to increase slowly from 240 aMW in 2024 to 268 aMW in 2043, an average annual compound growth rate of 0.6%. In the 50th-percentile scenario, irrigation load is projected to be 224 aMW in 2024 and 251 aMW in 2043, also at an average annual compound growth rate of 0.6%. In the 90th-percentile scenario, irrigation load is projected to be 260 aMW in 2024 and 288 aMW in 2043, an average annual compound growth rate of 0.5%. All irrigation load growth scenarios forecast slower growth than the system from 2024 to 2043. The individual irrigation load forecasts are summarized in Table 10 and illustrated in Figure 18.

Table 10. Irrigation load growth (aMW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
90th Percentile	260	264	271	288	0.5%
Anticipated Case	240	244	251	268	0.6%
50th Percentile	224	227	234	251	0.6%

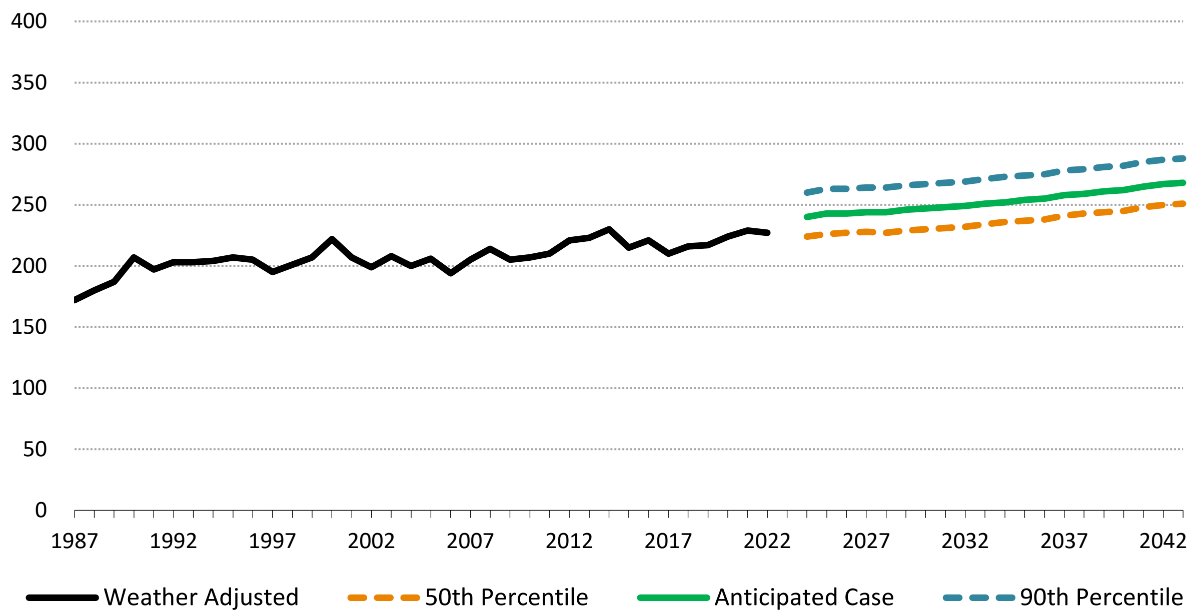


Figure 18. Forecast irrigation load (aMW)

The annual average loads in Table 10 and Figure 18 are calculated using 8,760 hours in a typical year. 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. During the summer, hourly irrigation loads can constitute nearly 900 MW. 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 slight increase of forecasted sales over this period is due to the expected increase in customer count from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers aiming 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 2023 IRP irrigation sales forecast model considers several factors affecting electricity sales to the irrigation class, including temperature; precipitation; 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 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 2022, the irrigation proportion of system sales was 13% due to the much higher relative growth in other customer classes.

In 1980, Idaho Power had about 10,850 active irrigation accounts. By 2022, the number of active irrigation accounts had increased to 20,936 and is projected to be nearly 25,900 at the end of the planning period in 2043.

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 tariff requires the company to serve requests for electric service greater than 20 MW under an under a special contract, or ESA, schedule negotiated between Idaho Power and each large-power customer. The ESA and tariff 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 Micron Technology, Inc.; Simplot Fertilizer Company (Simplot Fertilizer); INL; Brisbie, LLC (Meta Platforms, Inc.); and several anticipated new ESA customers. These ESA customers comprise the entire forecast category labeled "additional firm load".

In the anticipated forecast, additional firm load is expected to increase from 135 aMW in 2024 to 712 aMW in 2043, an average growth rate of 9.1% per year over the planning period (Table 11). The additional firm load energy and demand forecasts in the 50th- and 90th-percentile scenarios are identical to the anticipated-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 19.

Table 11. Additional firm load growth (aMW)

Growth	2024	2028	2033	2043	Annual Growth Rate 2024–2043
Anticipated Case	135	589	702	712	9.1%

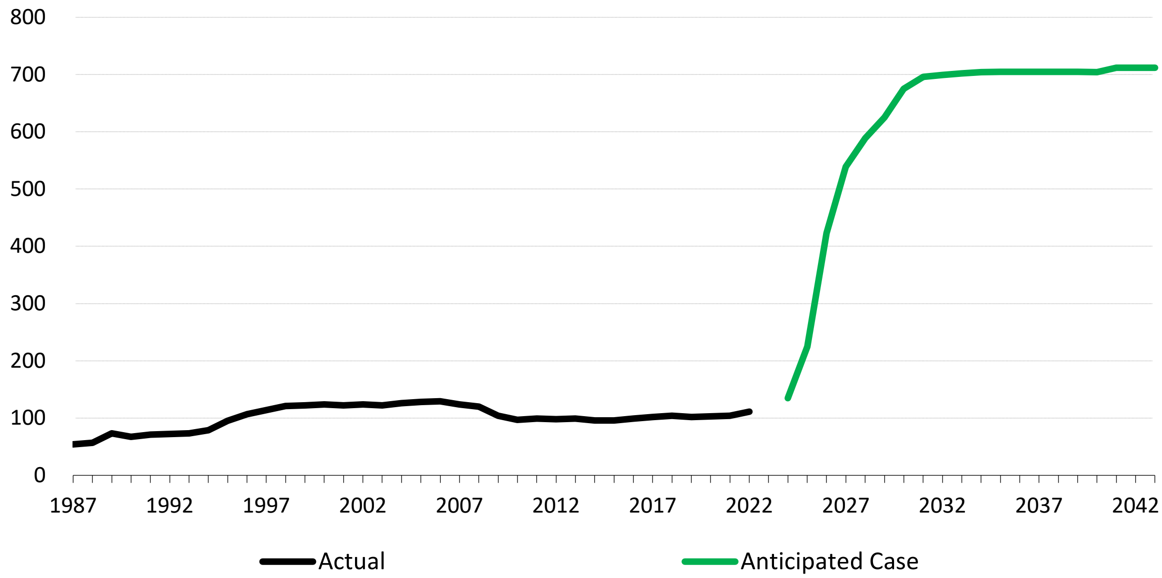


Figure 19. Forecast additional firm load (aMW)

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs more than 5,000 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 its products.

Simplot Fertilizer

This facility named the Don Plant is located just outside Pocatello, Idaho. The Don Plant is one of four fertilizer manufacturing plants in the J.R. Simplot Company's Agribusiness Group. Vital to fertilizer production at the Don Plant is phosphate ore mined at Simplot's Smoky Canyon mine on the Idaho/Wyoming border. According to industry standards, the Don Plant is rated as one of the most cost-efficient fertilizer producers in North America. In total, J.R. Simplot Company employs 2,000–3,000 workers throughout its Idaho locations.

Idaho National Laboratory

Idaho National Laboratory (INL) is one of the United States Department of Energy's (DOE) national laboratories and is the nation's lead laboratory for nuclear energy research, development, and demonstration. The DOE, in partnership with its contractors, is focused on performing research and development in energy programs and national defense. Much of the work to achieve this mission at INL is performed in government-owned and leased buildings on the Research and Education Campus (REC) in Idaho Falls, Idaho, and on the INL site, located approximately 50 miles west of Idaho Falls. INL is recognized as a critical economic driver and important asset to the state of Idaho with over 4,000 employees.

Brisbie, LLC (Meta Platforms, Inc.)

Idaho Power and Meta Platforms, Inc. (Meta) executed an ESA at the end of 2021, which is still pending commission approval at the time of this report. Meta has announced the construction of a new data center in Kuna, Idaho. With an estimated investment of $800 million, the Meta data center is projected to bring more than 1,200 jobs to Kuna during peak construction and 100 operational jobs. Meta plans to support 100% of its operations through the addition of new renewable resources connected to Idaho Power’s system. The renewables support will be facilitated through a Clean Energy Your Way (CEYW) arrangement.

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 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 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 DOE/Itron data is recognized in the industry as well-specified for the homogenous residential sector.

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 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 from standard to net-metering service (Schedules 6, 8, and 84) has risen dramatically, particularly for residential customers. While the current population of on-site generation customers is over 2% of the population of retail customers, recent adoption of solar is relatively strong for Idaho Power's service area.

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.

Schedules 6, 8, and 84 (net-metering) customer billing histories were compared to billing histories prior to customers becoming net-metering customers. The resulting average monthly impact per customer (in kWh) was then multiplied by forecasts of the Schedule 6, 8, and 84 residential, commercial, and irrigation 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 UPC sales impact per customer results in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2043, the annual residential sales forecast reduction was about 74 aMW, the commercial reduction was 3 aMW, and the irrigation reduction was 6 aMW.

Electric Vehicles

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). The data provides county-level registration which provides a basis for determining Idaho Power service-territory vehicle inventory. Other data sources for monitoring the outlook for PEV adoption includes the DOE, R.L. Polk, and Moody's Analytics.

The evolution of the PEV market shows high adoption continues to be evident in warmer climates, high-density and affluent population centers. The Idaho Power forecast for PEVs shows the service territory will continue to fall into the lower adoption ranges. 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 territory.

Demand Response

Existing and future demand response program impacts are not incorporated into the sales and load forecast. 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. A thorough description of Idaho Power's energy efficiency and demand response programs is included in *Appendix B—Demand-Side Management 2022 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 (2024–2043) (average annual percent change)

	Nominal	Real*
Electricity—2023 IRP	0.1%	-2.0%
Electricity—2021 IRP	0.9%	-1.2%
Natural Gas	0.3%	-1.7%

*adjusted for inflation

Figure 20 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1987 to 2022 and over the forecast period 2024 to 2043. Both nominal and real prices are shown. In the 2023 IRP, nominal electricity prices are expected to climb to about 11.8 cents per kWh by the end of the forecast period in 2043. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 2% annually. In the 2021 IRP, nominal electricity prices were assumed to climb to about 13 cents per kWh by 2043, and real electricity prices (inflation adjusted) were expected to decline over the forecast period at an average rate of 1.2% annually.

The electricity price forecast used to prepare the sales and load forecast in the 2023 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2021 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2021 IRP sales and load forecast, the electricity price forecast used to prepare the 2023 IRP sales and load forecast yields lower 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.

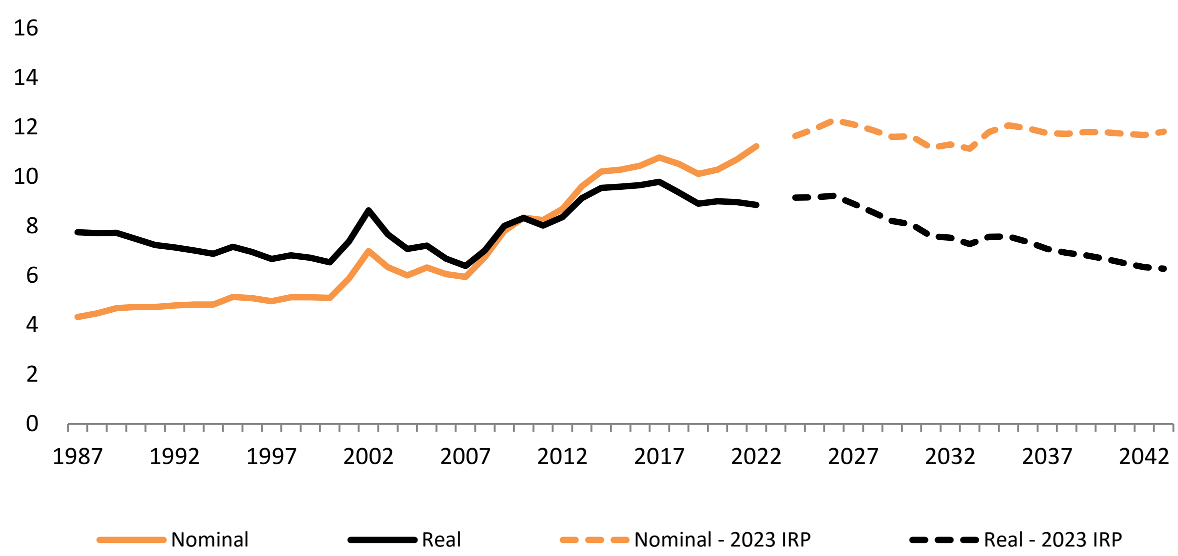


Figure 20. Forecast residential electricity prices (cents per kWh)

Electricity prices for Idaho Power customers increased significantly in 2001 and 2002, a direct result of the western United States 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% overall, an annual average compound growth rate of 0.8% annually. In contrast, from 2000 to 2010, nominal electricity prices rose 63% overall, an annual average compound growth rate of 4.2% annually. More recently, over the period 2010 to 2020, nominal electricity prices rose 23% overall, an annual average compound growth rate of 1.8% annually.

Figure 21 illustrates the average natural gas price paid by Intermountain Gas Company's residential customers over the historical period 1987 to 2021 and forecast prices from 2024 to 2043. Nominal natural gas prices are expected to rise throughout the forecast period, growing at an average rate of 0.3% per year. Real natural gas prices (adjusted for inflation) are expected to decrease over the same period at an average rate of 1.7% annually.

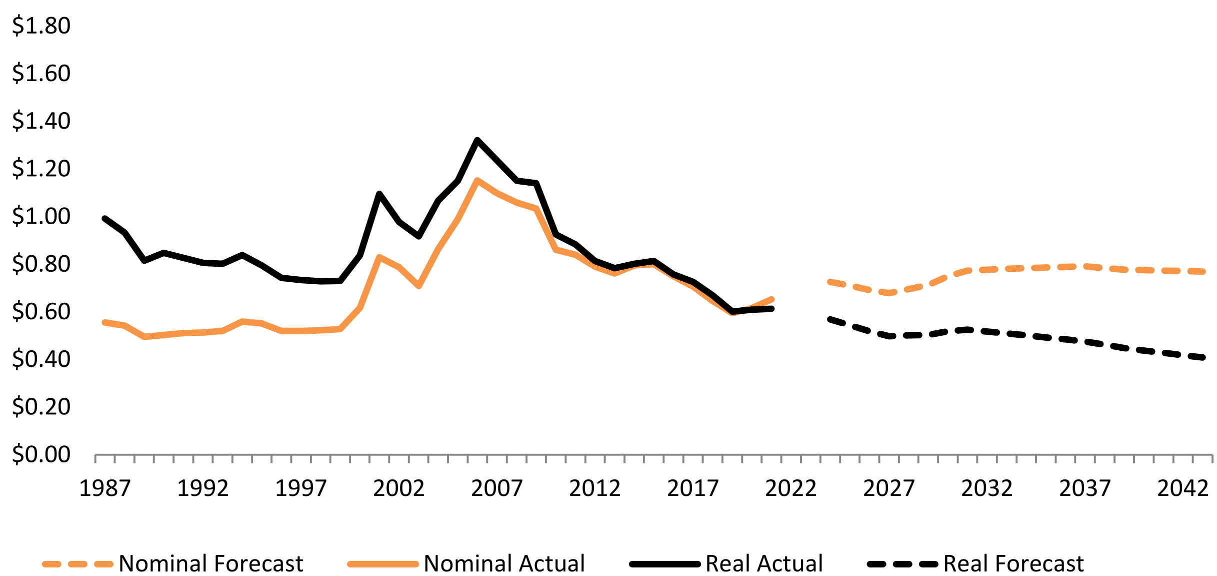


Figure 21. Forecast residential natural gas prices (dollars per therm)

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. S&P Global Platts provides the forecasts of long-term changes in nominal natural gas prices. In the 2023 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 billed 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. The most current system loss study was completed in 2023.

Hourly Load Forecast

As a result of stakeholder feedback and comments filed in the 2017 and 2019 IRPs, Idaho Power has leveraged several years of advanced metering infrastructure (AMI) data in its hourly load forecasting methodology. 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. It is important to note the monthly modeling mentioned drives the forecast used in the IRP. The hourly load forecast methodology described below simply allocates the monthly model regressions to each hour of the year.

Hourly Load Forecast Methodology

The company believes it is prudent to maintain the integrity of the historic long-term forecasting methodologies. The company concluded in 2021 that the hourly forecast should use a neural network. A neural network utilizes the stability of monthly sales data to calibrate and ground the hourly data via monthly peak regressions. This neural network was developed under counsel with Itron Forecasting. The company ensured this methodology employs control and flexibility on the neural network while remaining highly transparent.

Technical Specifications of Hourly Load Forecasting

To begin the process, the company engaged in consultation with Itron Forecasting. 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 an HDD or CDD 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.

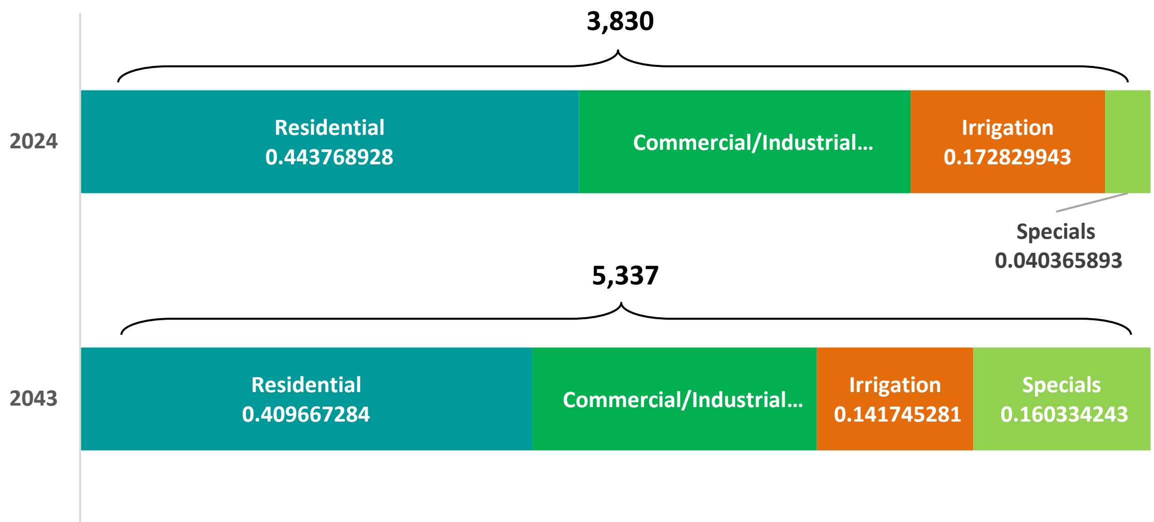
A distinct model is developed for each hour of the year to capture the full spectrum of temperature responsiveness. For each non-linear hourly model, an instantaneous derivative value is calculated along the curve to obtain the relationship of energy sales to temperature. A key initiative for Idaho Power 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 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.

Hourly System Load Forecast Design

The output from the neural network is joined with the abovementioned typical meteorological year 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 by 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.

The above process can be repeated for each major customer class to produce estimated contributions to system peak by customer class as shown in Figure 22.



*Total includes impact from losses

Figure 22. Class contribution to system peak

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 (excluding Astaris)

Historical Company System Sales and Load, 1982–2022 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1982	7,820		954
1983	8,045	2.9%	978
1984	8,107	0.8%	983
1985	8,256	1.8%	1,003
1986	8,359	1.2%	1,016
1987	8,499	1.7%	1,033
1988	8,834	3.9%	1,071
1989	9,201	4.2%	1,117
1990	9,559	3.9%	1,160
1991	9,741	1.9%	1,182
1992	9,963	2.3%	1,206
1993	10,274	3.1%	1,250
1994	10,663	3.8%	1,295
1995	11,137	4.4%	1,351
1996	11,467	3.0%	1,389
1997	11,755	2.5%	1,427
1998	12,240	4.1%	1,483
1999	12,548	2.5%	1,522
2000	12,928	3.0%	1,566
2001	13,062	1.0%	1,580
2002	12,791	-2.1%	1,552
2003	13,140	2.7%	1,592
2004	13,344	1.5%	1,616
2005	13,707	2.7%	1,667
2006	13,995	2.1%	1,697
2007	14,389	2.8%	1,745
2008	14,464	0.5%	1,746
2009	13,986	-3.3%	1,697
2010	13,835	-1.1%	1,677
2011	13,860	0.2%	1,684
2012	14,068	1.5%	1,706
2013	14,076	0.1%	1,720
2014	14,268	1.4%	1,733

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2015	14,134	-0.9%	1,721
2016	14,296	1.1%	1,740
2017	14,408	0.8%	1,754
2018	14,579	1.2%	1,777
2019	14,729	1.0%	1,798
2020	14,884	1.1%	1,815
2021	15,156	1.8%	1,858
2022	15,351	1.3%	1,877

Company System Load
Projected Company System Sales and Load, 2024–2043

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2024	15,958	1.9%	2,024
2025	16,577	3.9%	2,141
2026	17,544	5.8%	2,360
2027	18,464	5.2%	2,495
2028	19,060	3.2%	2,561
2029	19,514	2.4%	2,622
2030	20,117	3.1%	2,695
2031	20,461	1.7%	2,737
2032	20,671	1.0%	2,755
2033	20,840	0.8%	2,784
2034	21,026	0.9%	2,807
2035	21,186	0.8%	2,827
2036	21,359	0.8%	2,841
2037	21,515	0.7%	2,868
2038	21,690	0.8%	2,890
2039	21,863	0.8%	2,912
2040	22,032	0.8%	2,926
2041	22,251	1.0%	2,960
2042	22,407	0.7%	2,980
2043	22,561	0.7%	2,999

Residential Load

Historical Residential Sales and Load, 1982–2022 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1982	216,696		13,508	2,927		337
1983	219,849	1.5%	14,332	3,151	7.6%	358
1984	222,695	1.3%	14,005	3,119	-1.0%	355
1985	225,185	1.1%	13,821	3,112	-0.2%	355
1986	227,081	0.8%	14,073	3,196	2.7%	365
1987	228,868	0.8%	13,981	3,200	0.1%	365
1988	230,771	0.8%	14,251	3,289	2.8%	374
1989	233,370	1.1%	14,209	3,316	0.8%	379
1990	238,117	2.0%	14,271	3,398	2.5%	387
1991	243,207	2.1%	14,379	3,497	2.9%	400
1992	249,767	2.7%	14,102	3,522	0.7%	400
1993	258,271	3.4%	14,019	3,621	2.8%	415
1994	267,854	3.7%	13,992	3,748	3.5%	428
1995	277,131	3.5%	14,011	3,883	3.6%	443
1996	286,227	3.3%	13,774	3,943	1.5%	450
1997	294,674	3.0%	13,687	4,033	2.3%	460
1998	303,300	2.9%	13,778	4,179	3.6%	477
1999	312,901	3.2%	13,633	4,266	2.1%	487
2000	322,402	3.0%	13,411	4,324	1.4%	492
2001	331,009	2.7%	13,168	4,359	0.8%	495
2002	339,764	2.6%	12,687	4,311	-1.1%	493
2003	349,219	2.8%	12,820	4,477	3.9%	509
2004	360,462	3.2%	12,725	4,587	2.5%	523
2005	373,602	3.6%	12,715	4,750	3.6%	544
2006	387,707	3.8%	12,983	5,033	6.0%	574
2007	397,286	2.5%	13,036	5,179	2.9%	590
2008	402,520	1.3%	12,905	5,194	0.3%	591
2009	405,144	0.7%	12,730	5,157	-0.7%	587
2010	407,551	0.6%	12,463	5,079	-1.5%	579
2011	409,786	0.5%	12,405	5,083	0.1%	579
2012	413,610	0.9%	12,390	5,124	0.8%	580
2013	418,892	1.3%	12,043	5,045	-1.6%	577
2014	425,036	1.5%	11,965	5,086	0.8%	575
2015	432,275	1.7%	11,688	5,053	-0.7%	576
2016	440,362	1.9%	11,627	5,120	1.3%	583

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	448,800	1.9%	11,546	5,182	1.2%	590
2018	459,128	2.3%	11,361	5,216	0.7%	594
2019	471,298	2.7%	11,239	5,297	1.5%	607
2020	484,433	2.8%	11,401	5,523	4.3%	633
2021	499,216	3.1%	11,257	5,620	1.8%	642
2022	512,803	2.7%	11,151	5,718	1.8%	643

Projected Residential Sales and Load, 2024–2043

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2024	533,126	2.2%	10,793	5,754	1.1%	678
2025	543,708	2.0%	10,690	5,812	1.0%	687
2026	554,453	2.0%	10,563	5,857	0.8%	693
2027	565,646	2.0%	10,464	5,919	1.1%	701
2028	577,181	2.0%	10,388	5,996	1.3%	708
2029	588,906	2.0%	10,322	6,079	1.4%	720
2030	600,677	2.0%	10,254	6,159	1.3%	729
2031	612,333	1.9%	10,196	6,243	1.4%	739
2032	623,729	1.9%	10,137	6,323	1.3%	747
2033	634,783	1.8%	10,078	6,398	1.2%	758
2034	645,419	1.7%	10,011	6,461	1.0%	765
2035	655,575	1.6%	9,939	6,516	0.8%	772
2036	665,243	1.5%	9,893	6,581	1.0%	778
2037	674,440	1.4%	9,862	6,651	1.1%	788
2038	683,192	1.3%	9,833	6,718	1.0%	796
2039	691,515	1.2%	9,801	6,778	0.9%	804
2040	699,424	1.1%	9,770	6,833	0.8%	808
2041	706,941	1.1%	9,744	6,888	0.8%	817
2042	714,108	1.0%	9,722	6,943	0.8%	824
2043	720,959	1.0%	9,700	6,993	0.7%	830

Commercial Load

Historical Commercial Sales and Load, 1982–2022 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1982	30,167		54,137	1,633		186
1983	30,776	2.0%	52,637	1,620	-0.8%	185
1984	31,554	2.5%	53,650	1,693	4.5%	193
1985	32,418	2.7%	54,285	1,760	4.0%	201
1986	33,208	2.4%	54,057	1,795	2.0%	205
1987	33,975	2.3%	53,611	1,821	1.5%	208
1988	34,723	2.2%	54,465	1,891	3.8%	216
1989	35,638	2.6%	55,525	1,979	4.6%	226
1990	36,785	3.2%	55,940	2,058	4.0%	235
1991	37,922	3.1%	56,243	2,133	3.7%	244
1992	39,022	2.9%	56,674	2,212	3.7%	252
1993	40,047	2.6%	58,522	2,344	6.0%	268
1994	41,629	4.0%	58,445	2,433	3.8%	278
1995	43,165	3.7%	58,918	2,543	4.5%	292
1996	44,995	4.2%	62,292	2,803	10.2%	320
1997	46,819	4.1%	62,380	2,921	4.2%	333
1998	48,404	3.4%	62,833	3,041	4.1%	348
1999	49,430	2.1%	64,354	3,181	4.6%	363
2000	50,117	1.4%	66,141	3,315	4.2%	379
2001	51,501	2.8%	67,665	3,485	5.1%	397
2002	52,915	2.7%	65,004	3,440	-1.3%	393
2003	54,194	2.4%	64,459	3,493	1.6%	398
2004	55,577	2.6%	64,160	3,566	2.1%	407
2005	57,145	2.8%	63,620	3,636	2.0%	415
2006	59,050	3.3%	63,622	3,757	3.3%	429
2007	61,640	4.4%	63,448	3,911	4.1%	447
2008	63,492	3.0%	62,295	3,955	1.1%	449
2009	64,151	1.0%	59,859	3,840	-2.9%	439
2010	64,421	0.4%	58,905	3,795	-1.2%	432
2011	64,921	0.8%	58,602	3,805	0.3%	434
2012	65,599	1.0%	59,032	3,872	1.8%	440
2013	66,357	1.2%	58,682	3,894	0.6%	446
2014	67,113	1.1%	59,057	3,963	1.8%	451
2015	68,000	1.3%	58,722	3,993	0.7%	456

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2016	68,883	1.3%	58,190	4,008	0.4%	457
2017	69,850	1.4%	57,964	4,049	1.0%	461
2018	71,104	1.8%	57,839	4,113	1.6%	470
2019	72,332	1.7%	57,034	4,125	0.3%	471
2020	73,702	1.9%	54,610	4,025	-2.4%	458
2021	75,282	2.1%	54,826	4,127	2.5%	471
2022	76,672	1.8%	54,983	4,216	2.1%	483

Projected Commercial Sales and Load, 2024–2043

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2024	78,882	1.4%	54,802	4,323	1.3%	500
2025	79,984	1.4%	54,353	4,347	0.6%	504
2026	81,175	1.5%	54,083	4,390	1.0%	509
2027	82,419	1.5%	53,521	4,411	0.5%	512
2028	83,738	1.6%	53,094	4,446	0.8%	515
2029	85,121	1.7%	52,569	4,475	0.6%	520
2030	86,551	1.7%	52,271	4,524	1.1%	525
2031	88,012	1.7%	51,706	4,551	0.6%	529
2032	89,487	1.7%	51,348	4,595	1.0%	532
2033	90,965	1.7%	50,853	4,626	0.7%	537
2034	92,433	1.6%	50,520	4,670	0.9%	543
2035	93,885	1.6%	50,244	4,717	1.0%	548
2036	95,314	1.5%	49,820	4,749	0.7%	550
2037	96,718	1.5%	49,493	4,787	0.8%	556
2038	98,098	1.4%	49,253	4,832	0.9%	562
2039	99,452	1.4%	49,088	4,882	1.0%	567
2040	100,781	1.3%	48,855	4,924	0.9%	571
2041	102,086	1.3%	48,658	4,967	0.9%	577
2042	103,368	1.3%	48,409	5,004	0.7%	582
2043	104,630	1.2%	48,177	5,041	0.7%	586

Irrigation Load

Historical Irrigation Sales and Load, 1982–2022 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1982	11,312		152,949	1,730		198
1983	11,133	-1.6%	148,748	1,656	-4.3%	190
1984	11,375	2.2%	136,037	1,547	-6.6%	175
1985	11,576	1.8%	134,360	1,555	0.5%	176
1986	11,308	-2.3%	135,238	1,529	-1.7%	175
1987	11,254	-0.5%	133,394	1,501	-1.8%	172
1988	11,378	1.1%	138,651	1,578	5.1%	180
1989	11,957	5.1%	137,247	1,641	4.0%	187
1990	12,340	3.2%	147,161	1,816	10.7%	207
1991	12,484	1.2%	138,688	1,731	-4.7%	197
1992	12,809	2.6%	138,914	1,779	2.8%	203
1993	13,078	2.1%	135,086	1,767	-0.7%	203
1994	13,559	3.7%	132,262	1,793	1.5%	204
1995	13,679	0.9%	132,474	1,812	1.0%	207
1996	14,074	2.9%	127,844	1,799	-0.7%	205
1997	14,383	2.2%	118,942	1,711	-4.9%	195
1998	14,695	2.2%	119,947	1,763	3.0%	201
1999	14,912	1.5%	122,035	1,820	3.2%	207
2000	15,253	2.3%	128,235	1,956	7.5%	222
2001	15,522	1.8%	116,730	1,812	-7.4%	207
2002	15,840	2.0%	110,152	1,745	-3.7%	199
2003	16,020	1.1%	113,351	1,816	4.1%	208
2004	16,297	1.7%	108,374	1,766	-2.7%	200
2005	16,936	3.9%	106,011	1,795	1.7%	206
2006	17,062	0.7%	99,145	1,692	-5.8%	194
2007	17,001	-0.4%	105,373	1,791	5.9%	205
2008	17,428	2.5%	108,565	1,892	5.6%	214
2009	17,708	1.6%	101,586	1,799	-4.9%	205
2010	17,846	0.8%	102,150	1,823	1.3%	207
2011	18,292	2.5%	100,382	1,836	0.7%	210
2012	18,675	2.1%	103,772	1,938	5.5%	221
2013	19,017	1.8%	102,889	1,957	1.0%	223
2014	19,328	1.6%	104,262	2,015	3.0%	230
2015	19,756	2.2%	95,494	1,887	-6.4%	215

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2016	20,042	1.4%	96,629	1,937	2.7%	221
2017	20,246	1.0%	90,202	1,826	-5.7%	210
2018	20,459	1.1%	92,540	1,893	3.7%	216
2019	20,566	0.5%	91,922	1,890	-0.1%	217
2020	20,804	1.2%	94,667	1,969	4.2%	224
2021	21,066	1.3%	91,979	1,938	-1.6%	229
2022	21,324	1.2%	89,590	1,910	-1.4%	227

Projected Irrigation Sales and Load, 2024–2043

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2024	21,747	1.2%	90,344	1,965	1.8%	240
2025	21,997	1.1%	90,140	1,983	0.9%	243
2026	22,249	1.1%	89,185	1,984	0.1%	243
2027	22,498	1.1%	88,598	1,993	0.5%	244
2028	22,750	1.1%	87,821	1,998	0.2%	244
2029	22,999	1.1%	87,110	2,003	0.3%	246
2030	23,250	1.1%	86,619	2,014	0.5%	247
2031	23,502	1.1%	86,151	2,025	0.5%	248
2032	23,751	1.1%	85,746	2,037	0.6%	249
2033	24,002	1.1%	85,405	2,050	0.7%	251
2034	24,253	1.0%	85,104	2,064	0.7%	252
2035	24,502	1.0%	84,841	2,079	0.7%	254
2036	24,757	1.0%	84,585	2,094	0.7%	255
2037	25,007	1.0%	84,363	2,110	0.7%	258
2038	25,254	1.0%	84,148	2,125	0.7%	259
2039	25,505	1.0%	83,936	2,141	0.7%	261
2040	25,754	1.0%	83,732	2,156	0.7%	262
2041	26,006	1.0%	83,524	2,172	0.7%	265
2042	26,257	1.0%	83,318	2,188	0.7%	267
2043	26,508	1.0%	83,095	2,203	0.7%	268

Industrial Load

Historical Industrial Sales and Load, 1982–2022 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1982	122		9,504,283	1,162		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

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2017	117	-1.1%	20,996,425	2,453	3.9%	280
2018	115	-1.6%	21,274,929	2,447	-0.3%	280
2019	124	8.0%	20,288,866	2,521	3.0%	288
2020	124	-0.3%	19,912,671	2,466	-2.2%	283
2021	124	0.0%	20,671,453	2,560	3.8%	294
2022	123	-0.8%	20,844,705	2,560	0.0%	294

Projected Industrial Sales and Load, 2024–2043

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2024	123	0.8%	22,202,622	2,731	2.5%	311
2025	124	0.8%	22,422,106	2,780	1.8%	318
2026	124	0.0%	22,646,315	2,808	1.0%	321
2027	125	0.8%	22,681,295	2,835	1.0%	324
2028	126	0.8%	22,710,399	2,862	0.9%	326
2029	128	1.6%	22,584,636	2,891	1.0%	330
2030	130	1.6%	22,479,994	2,922	1.1%	334
2031	130	0.0%	22,745,901	2,957	1.2%	338
2032	131	0.8%	22,833,038	2,991	1.2%	341
2033	131	0.0%	23,126,588	3,030	1.3%	346
2034	131	0.0%	23,445,984	3,071	1.4%	351
2035	132	0.8%	23,592,069	3,114	1.4%	356
2036	133	0.8%	23,742,442	3,158	1.4%	360
2037	134	0.8%	23,895,073	3,202	1.4%	366
2038	135	0.7%	24,076,426	3,250	1.5%	372
2039	135	0.0%	24,447,379	3,300	1.5%	377
2040	136	0.7%	24,636,813	3,351	1.5%	382
2041	138	1.5%	24,640,741	3,400	1.5%	389
2042	138	0.0%	25,003,264	3,450	1.5%	394
2043	139	0.7%	25,188,594	3,501	1.5%	400

Additional Firm Sales and Load

Historical Additional Firm Sales and Load, 1982–2022

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1982	367		39
1983	425	15.7%	45
1984	466	9.7%	50
1985	471	1.1%	50
1986	482	2.4%	51
1987	502	4.2%	54
1988	530	5.6%	57
1989	671	26.5%	73
1990	625	-6.9%	67
1991	661	5.8%	71
1992	680	2.9%	72
1993	689	1.3%	73
1994	740	7.5%	79
1995	878	18.6%	95
1996	988	12.6%	107
1997	1,048	6.0%	114
1998	1,113	6.2%	121
1999	1,121	0.8%	122
2000	1,142	1.9%	124
2001	1,118	-2.1%	122
2002	1,139	1.9%	124
2003	1,120	-1.7%	122
2004	1,156	3.3%	126
2005	1,175	1.6%	128
2006	1,189	1.2%	129
2007	1,141	-4.0%	124
2008	1,114	-2.4%	120
2009	965	-13.4%	104
2010	907	-6.0%	97
2011	906	0.0%	99
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

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
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%	111

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

Projected Additional Firm Sales and Load, 2024–2043

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2024	1,186	7.6%	135
2025	1,972	66.4%	225
2026	3,702	87.7%	423
2027	4,717	27.4%	539
2028	5,175	9.7%	589
2029	5,478	5.9%	625
2030	5,910	7.9%	675
2031	6,097	3.2%	696
2032	6,141	0.7%	699
2033	6,149	0.1%	702
2034	6,171	0.4%	704
2035	6,172	0.0%	705
2036	6,193	0.3%	705
2037	6,177	-0.3%	705
2038	6,176	0.0%	705
2039	6,174	0.0%	705
2040	6,184	0.2%	704
2041	6,234	0.8%	712
2042	6,234	0.0%	712
2043	6,234	0.0%	712

*Includes Micron Technology, Simplot Fertilizer, and the INL