IDAHO POWER®
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A VIEW
FROM ABOVE

IRP
INTEGRATED RESOURCE PLAN

APPENDIX A: **SALES & LOAD FORECAST**

SAFE HARBOR STATEMENT

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INTRODUCTION

Idaho Power has prepared *Appendix A—Sales and Load Forecast* as part of the *2021 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 2021 through 2040.

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 2% during the forecast period. The growth in the number of households within individual counties in Idaho Power's service area is projected to grow faster than the remainder of the state over the planning period. Similarly, the number of households in the Boise–Nampa MSA is projected to grow faster than the state of Idaho as well, at an annual rate of 2.6% 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 forecast of the anticipated scenario shows, Idaho Power's system load is forecast to increase to 2,482 average megawatts (aMW) by 2040 from 1,895 aMW in 2021, representing an average yearly growth rate of 1.4% over the 20-year planning period (2021–2040). 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 4,700 megawatts (MW) in 2040 from the all-time system peak of 3,751 MW that occurred on Wednesday, June 30, 2021, at 5 p.m. Idaho Power's system peak increases at an average growth rate of 1.4% per year over the 20-year planning period (2021–2040) under this case. Over this same term, the number of Idaho Power active retail customers is expected to increase from the December 2020 level of 586,071 customers to nearly 851,849 customers by year-end 2040.

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 2020 Annual Report*, which is incorporated into this IRP document as Appendix B. Idaho Power also recognizes the impact of on-site generation and electric vehicles in its service territory and does include the energy reduction or addition in the long-term sales and load forecast due to their impact. Further discussions of these assumptions are presented in the appropriate section.

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. In addition, the price and volatility of substitute fuels, such as natural gas, may also impact future demand for electricity. The uncertainty associated with such changes is reflected in the economic high and low load growth scenarios described previously. The alternative sales and load scenarios in *Appendix A—Sales and Load Forecast* were prepared under the assumption that Idaho Power's geographic service area remains unchanged during the planning period.

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

2021 IRP SALES AND LOAD FORECAST

Average Load

The economic and demographic variables driving the 2021 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 is attributable to both work-from-home edicts as well as continued strong in-migration trends.
Negative energy use was initially exhibited by the commercial and industrial classes but have since stabilized and, overall, rebounded quickly. Irrigation sales were mostly unaffected by the pandemic. It is expected that economic conditions return to long-term fundamentals during the 2021 IRP forecast term. COVID-19 impacts are further discussed in the individual class sections below. Additional significant factors and considerations that influenced the outcome of the 2021 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 case load forecast of energy and peak-hour demand, Idaho Power assumes average temperatures and precipitation over a 30-year meteorological measurement period or defined as normal climatology. Probabilistic variations of weather are also analyzed.
- The economic forecast used for the 2021 IRP reflects the continued expansion of the Idaho economy in the near-term and reversion to the long-term trend of the service area economy. Customer growth was at a near standstill until 2012, but since then acceleration of net migration and business investment has resulted in renewed positive activity. The state of Idaho had the highest residential population growth rate of any state in the United States over the past 5 years (ending 2020). Customer additions experienced prior to the housing bubble are expected to continue.
- Conservation impacts, including DSM energy efficiency programs, codes, and standards, and other naturally occurring efficiencies are integrated into the sales forecast. These impacts are expected to continue to erode use per customer over much of the forecast period. Impacts of demand response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning (i.e., demand response is treated as a supply-side peaking resource). The amount of committed and implemented DSM programs for each month of the planning period is

shown in the load and resource balance in *Appendix C—Technical Appendix*. Additional impacts from on-site generation customers and electric vehicles are included as well.

- Although interest from large customers has been robust, there is some uncertainty associated with these industrial and special contract customers due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an uncertain magnitude of the energy and peak-demand requirements. The 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 2021 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2019 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2019 IRP sales and load forecast, the 2021 IRP price 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.
- As discussed above, the response to the novel corona virus influenced electric usage behavior across the major rate classes. Discernably, these impacts tended to balance one another; e.g., increased residential consumption due to work-from-home behavior was offset by decreased use from office and other commercial facilities. While these impacts continue to play out in decreasing importance, the impact on the long-term forecast horizon is essentially inconsequential.

Peak-Hour Demands

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

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

- The all-time system summer peak demand was 3,751 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. Idaho Power's winter peak-hour load record is 2,527 MW, recorded on January 6, 2017, at 9 a.m. and matched the previous record peak dated December 10, 2009, at 8 a.m.
- The peak model develops peak-scenario impacts based on historical probabilities of peak day temperatures at the 50th, 90th, and 95th-percentiles of occurrence for each month of the year. These average peak-day temperature drivers are calculated over the 1991 to 2020 time period (the most recent 30 years).
- The 2021 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 are constructed by developing a separate energy forecast for each of the major customer classes: residential, commercial, irrigation, industrial, and special contracts. In conjunction with this load (or sales) forecast, an 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 anticipated average load forecast assumes median temperatures and median precipitation (i.e., there is a 50% chance loads will be higher or lower than the anticipated loads due to colder-than-median or hotter-than-median temperatures or wetter-than-median or drier-than-median precipitation). Since actual loads can vary significantly depending on weather conditions, alternative scenarios were developed that address load variability due to varying weather conditions.

Illustratively, Idaho Power's maximum annual average load occurs when the highest recorded levels of heating degree days (HDD) are assumed in winter and the highest recorded levels of cooling and growing degree days (CDD and GDD) combined with the lowest recorded level of precipitation are assumed in summer. Conversely, the minimum annual average load occurs when the opposite of what is described above takes place. In the 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 1991 to 2020 (the most recent 30 years) was 1,024 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 1,130 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 the above mentioned two scenarios allows the careful examination of load variability and how it may impact future resource requirements, it is important to understand that the probabilities associated with these forecasts apply to each month. This assumes temperatures and precipitation would maintain at the 70th-percentile or 90th-percentile level continuously, throughout the entire year. Table 1 summarizes the load scenarios prepared for the 2021 IRP.

Table 1. Average load and peak-demand forecast scenarios

Scenario	Weather Probability	Probability of Exceeding	Weather Driver
Forecasts of Average Load			
90th Percentile	90%	1 in 10 years	HDD, CDD, GDD, precipitation
70th Percentile	70%	3 in 10 years	HDD, CDD, GDD, precipitation
Anticipated Case	50%	1 in 2 years	HDD, CDD, GDD, precipitation
Forecasts of Peak Demand			
95th Percentile	95%	1 in 20 years	Peak-day temperatures
90th Percentile	90%	1 in 10 years	Peak-day temperatures
50th Percentile	50%	1 in 2 years	Peak-day temperatures

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

Table 2. System load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	2,001	2,197	2,427	2,620	1.4%
70th Percentile	1,941	2,132	2,357	2,541	1.4%
Anticipated Case	1,895	2,082	2,304	2,482	1.4%

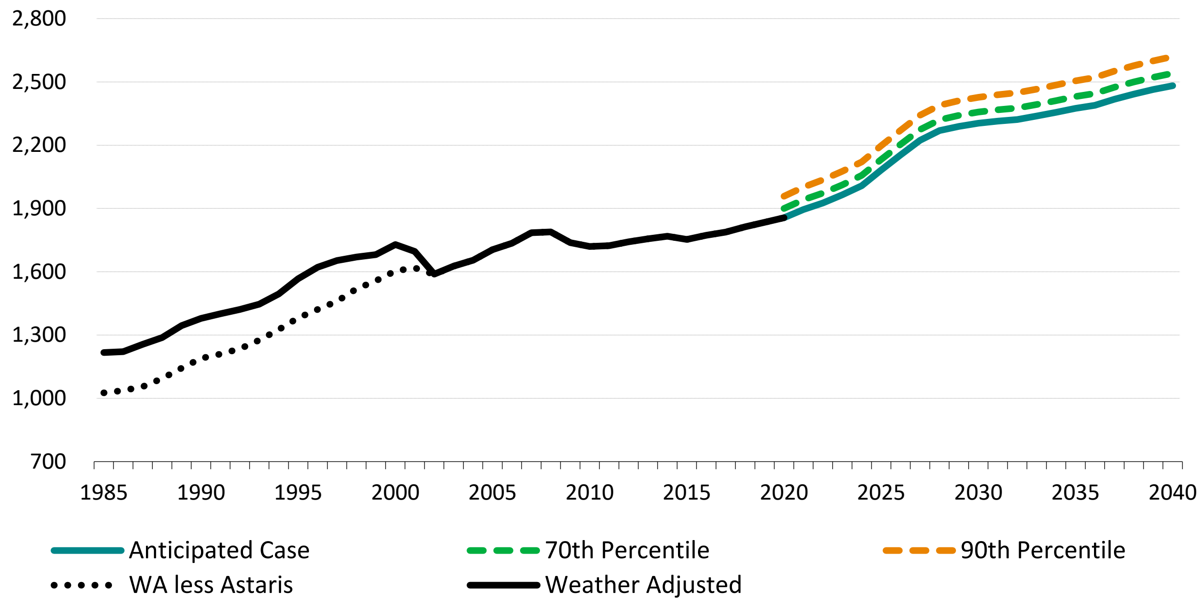

Figure 1. **Forecast system load (aMW)**[1]

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 2021 to 2040 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 (1996–2020).

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 (1996–2020).

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

[1] The Astaris elemental phosphorous plant (previously FMC) was located at the western edge of Pocatello, Idaho. Although no longer a customer of Idaho Power, Astaris had been Idaho Power's largest individual customer and, in some years, averaged nearly 200 aMW each month. In April 2002, the special contract between Astaris and Idaho Power was terminated.

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 special contracts (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 1.4% per year over the 20-year planning period. The low scenario projects the system load will increase at an average rate of 1.1% per year throughout the forecast period. The high scenario projects a load growth of 1.8% 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	2021	2025	2030	2040	Annual Growth Rate 2021–2040
Low	1,859	1,991	2,166	2,277	1.1%
Anticipated	1,895	2,082	2,304	2,482	1.4%
High	1,942	2,190	2,461	2,731	1.8%

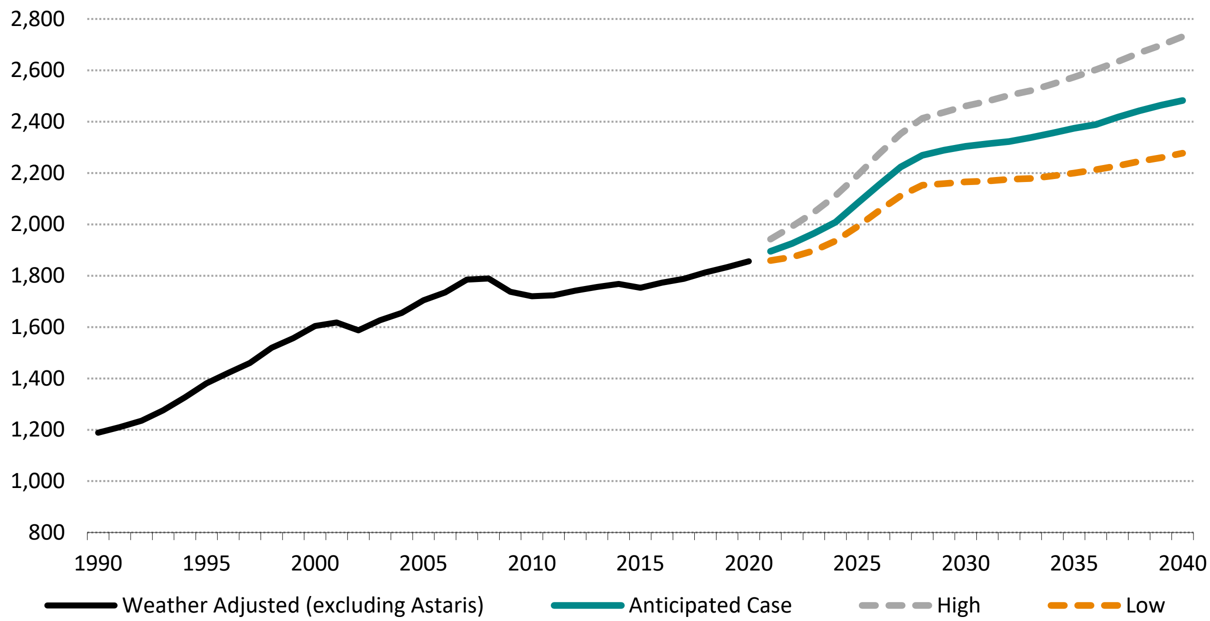

Figure 2. Forecast system load (aMW)

COMPANY SYSTEM LOAD

System load is the sum of the individual loads of residential, commercial, industrial, and irrigation customers, as well as special contracts (including past sales to Astaris) and 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 1.4% per year from 2021 to 2040. Company system load projections are reported in Table 2 and shown in Figure 1.

In the anticipated forecast, the company system load is expected to increase from 1,895 aMW in 2021 to 2,482 aMW in 2040, an average annual growth rate of 1.4%. In the weather sensitive scenarios, the 70th-percentile and 90th-percentile forecasts, the company system load is expected to increase from 1,941 aMW in 2021 to 2,541 aMW by 2040 and increase from 2,001 aMW in 2021 to 2,620 aMW, respectively. All scenarios have an average growth rate of 1.4% per year over the planning period. In the economic probability scenarios, the company system load is expected to increase in the low case from 1,859 aMW in 2021 to 2,277 aMW in 2040, an average annual growth rate of 1.1% and in the high case from 1,942 aMW to 2,731 aMW, an average annual growth rate of 1.8% (Table 2).

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 16% higher in 2040, gaining 0.9 million megawatt-hours (MWh) over 2021. Commercial sales are expected to be 19% higher, or 0.8 million MWh, followed by industrial (35% higher, or 0.9 million additional MWh) and irrigation (12% higher in 2040 than 2021). Additional firm sales are expected to more than triple by 2040, gaining 2.1 million MWh over 2021.

In addition to the above anticipated sales forecast, differing weather probabilities, high and low economic cases, and alternative sales and load cases were developed for analysis within the

2021 IRP. These include high growth within commercial and industrial classification of an additional approximate 250 MW of capacity requirements, high penetration future of building and transportation electrification, and future potential climate change impacts to the load forecast.

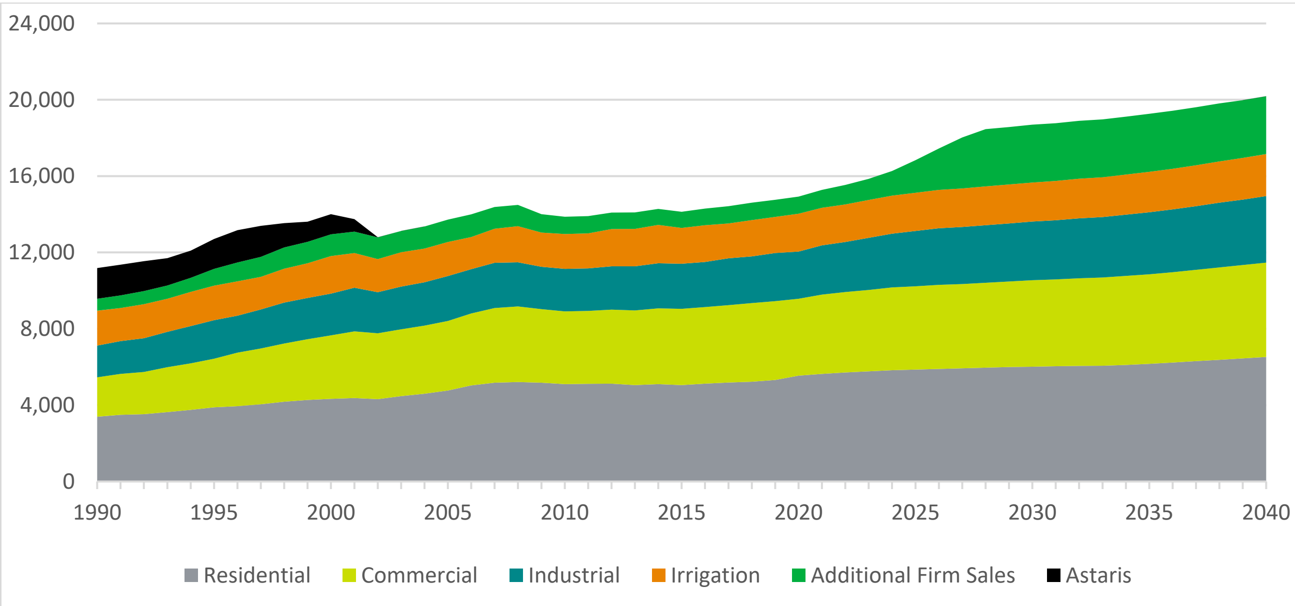

Figure 3. **Composition of system company electricity sales (thousands of MWh)**

COMPANY SYSTEM PEAK

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

Seasonal Peak Forecast

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

The all-time system summer peak demand was 3,751 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 (A/C) 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 3,771 MW in 2021 to 4,868 MW in 2040. In the 90th-percentile forecast, the system summer peak load is expected to increase from 3,745 MW in 2021 to 4,842 MW in 2040. Finally, in the 50th-percentile, or anticipated case, the system summer peak load increases from 3,603 MW in 2021 to 4,700 MW in 2040. All of which represent an average summer peak growth rate of 1.4% per year over the planning period (Table 5).

Table 5. System summer peak load growth (MW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
95th Percentile	3,771	4,071	4,421	4,868	1.4%
90th Percentile	3,745	4,045	4,394	4,842	1.4%
50th Percentile	3,603	3,903	4,252	4,700	1.4%

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

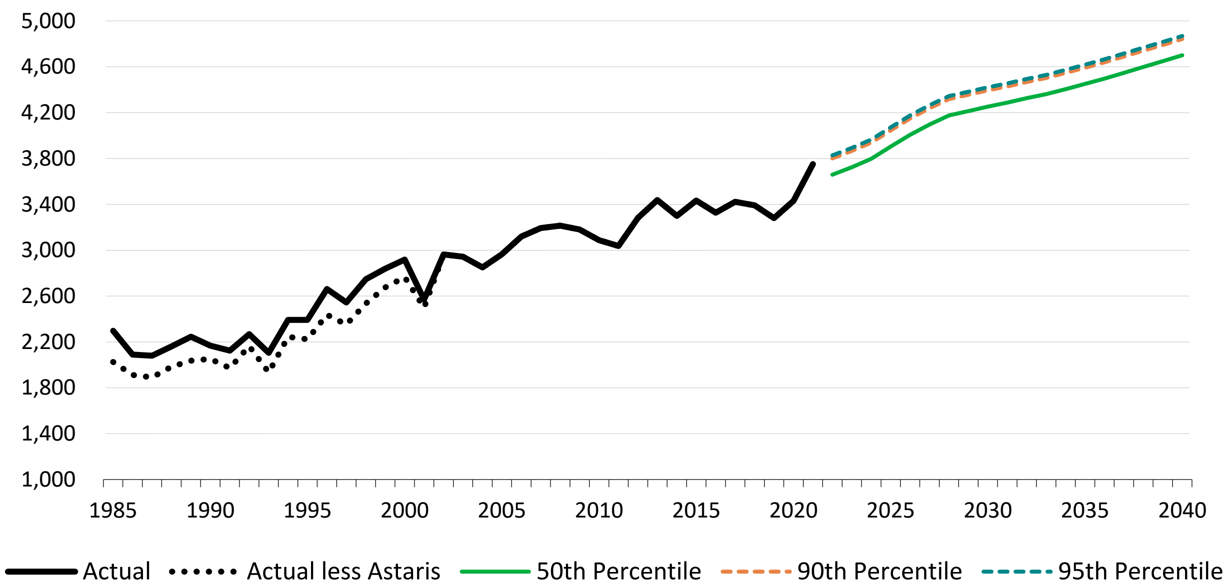

Figure 4. Forecast system summer peak (MW)

As of December 31, 2019, the all-time system winter peak demand of 2,527 MW, realized on Thursday, December 10, 2009, at 8 a.m. was matched on 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 2,699 MW in 2021 to 3,328 MW in 2040, an average growth rate of 1.1% per year over the planning period. In the 90th-percentile forecast, the system winter peak load is expected to increase from 2,584 MW in 2021 to 3,262 MW in 2040, an average growth rate of 1.2% per year over the planning period. In the 50th-percentile, or anticipated case forecast, the system winter peak load is expected to increase from 2,367 MW in 2021 to 3,132 MW in 2040, an average growth rate of 1.5% per year over the planning period. This data is represented in Table 6. The three scenarios of projected system winter peak load are illustrated in Figure 5.[2]

[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 1991 to 2020 time (the most recent 30 years).

Table 6. System winter peak load growth (MW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
95th Percentile	2,699	2,918	3,142	3,328	1.1%
90th Percentile	2,584	2,803	3,028	3,262	1.2%
50th Percentile	2,367	2,586	2,878	3,132	1.5%

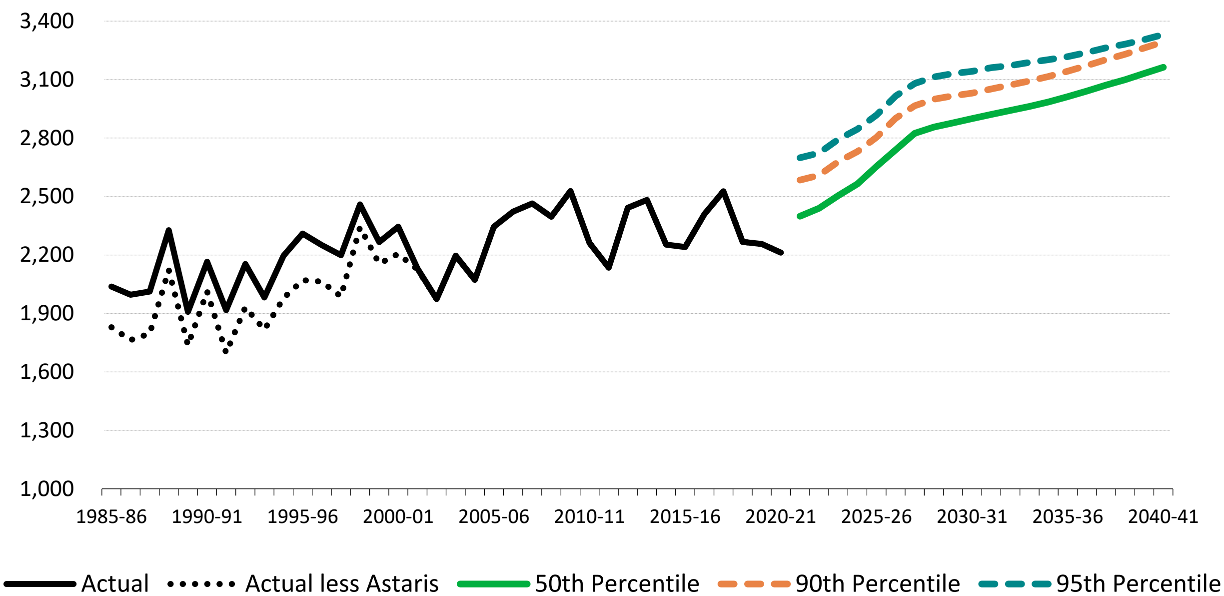

Figure 5. Forecast system winter peak (MW)

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

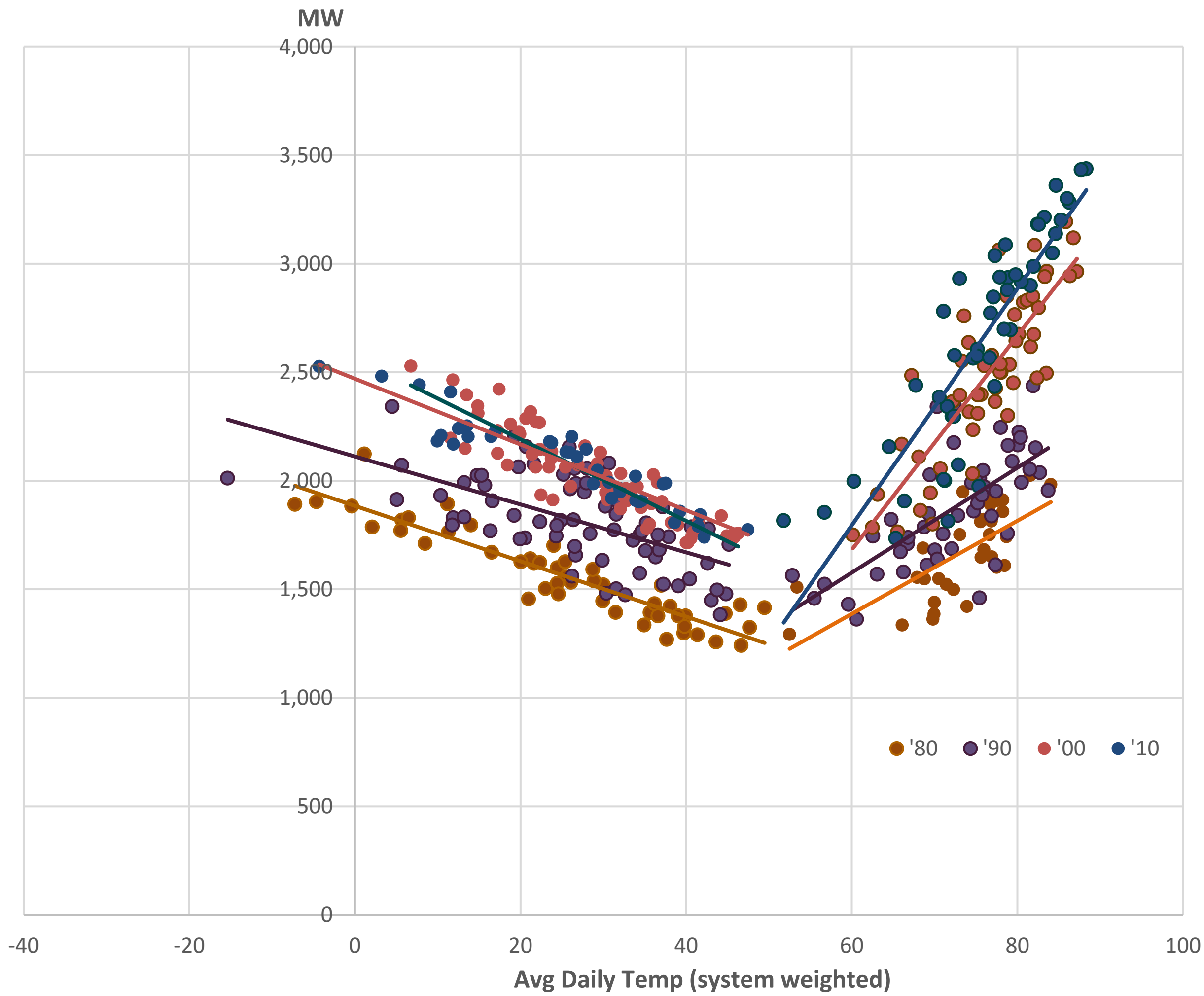

Figure 6. Idaho Power monthly peaks (MW)

Note that the 2021 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. Demand response program impacts are accounted for in the IRP load and resource balance and are reflected as a reduction in peak demand.

Peak Model Design

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

The forecast of average peak-day temperatures is a key driver of the monthly system peak models. The normal average peak-day temperature drivers are calculated over the 1991 to 2020 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}, 90^{th}, and 95^{th} percentiles of occurrence for each month of the year.

Note the summertime (June, July, and August) system peak regression models were re-specified to account for the upward trend in weighted average peak-day temperatures over time. The trendlines were fitted to the historical weighted average peak-day temperatures and then projected through the end of the forecast period, the year 2040. 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 anticipated residential load is forecast to increase from 644 aMW in 2021 to 743 aMW in 2040, an average annual compound growth rate of 0.8%. In the 70th-percentile scenario, the residential load is forecast to increase from 664 aMW in 2021 to 773 aMW in 2040, an average annual compound growth rate of 0.8%, matching the anticipated residential growth rate. The residential load forecasts are reported in Table 7 and shown in Figure 7.

Table 7. Residential load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	691	723	746	812	0.9%
70th Percentile	664	692	712	773	0.8%
Anticipated Case	644	670	687	743	0.8%

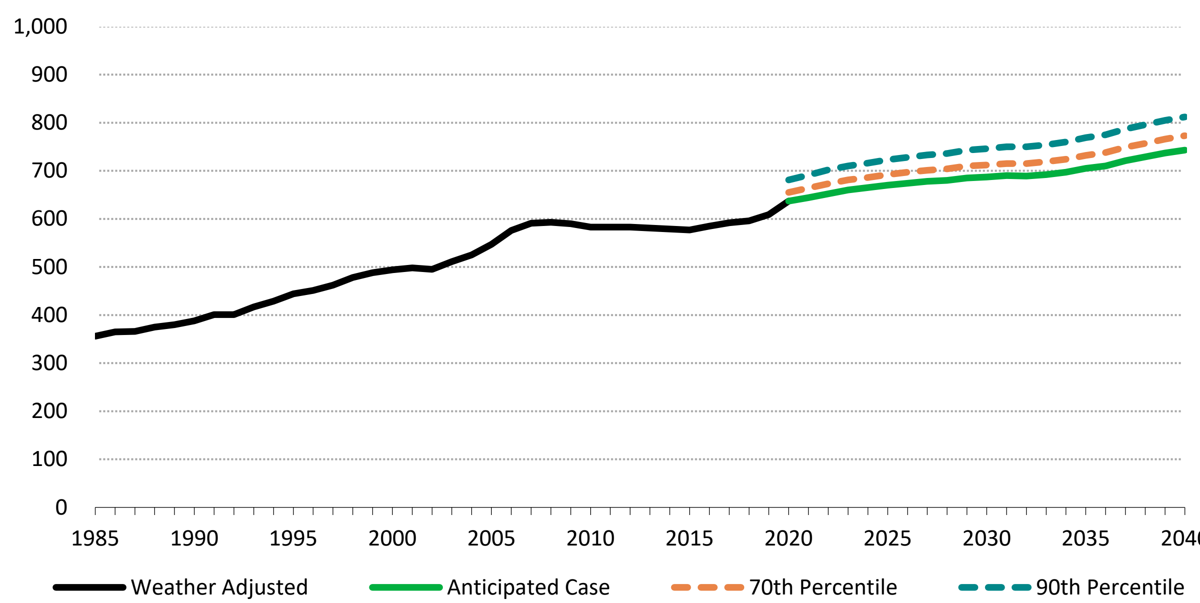

Figure 7. Forecast residential load (aMW)

Sales to residential customers made up 30% of Idaho Power's system sales in 1990 and 37% of system sales in 2020. The number of residential customers is projected to increase to nearly 719,500 by December 2040.

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 use per customer 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 use per customer to stabilize through 2007. However, conservation efforts have placed downward pressure on residential use per customer since that point. This trend is expected to continue, declining at 1.1% per year, as the average sales per residential customer are expected to decrease to approximately 9,100 kWh per year by 2040. Average annual sales per residential customer are shown in Figure 8. Although, it is important to note—as evident in figures 7 and 8—the impacts of the COVID pandemic on residential electricity sales (Figure 7) and residential use-per-customer (Figure 8). Major shifts in early 2020 to working and schooling from home, which required retooling homes with computers and electronics, served to boost residential electricity sales and use-per-customer. Residential sales (weather-adjusted) were 4% to 5% higher in 2020 than 2019. In addition to the overall increase in use per customer, the pandemic accelerated in-migration allowing those searching for affordable housing, a more reasonable cost of living, and ability to work from home to move from larger, more populated metro areas. This impact is fortified by Idaho having the highest population growth rate of any state in the United States over the past 5 years (ending 2019)[3] which continues today, as evidenced by Idaho Power's strong customer growth through year-to-date 2021.

[3] United States Census Bureau Population, Population Change, and Estimated Components of Population Change 2010 to 2019.

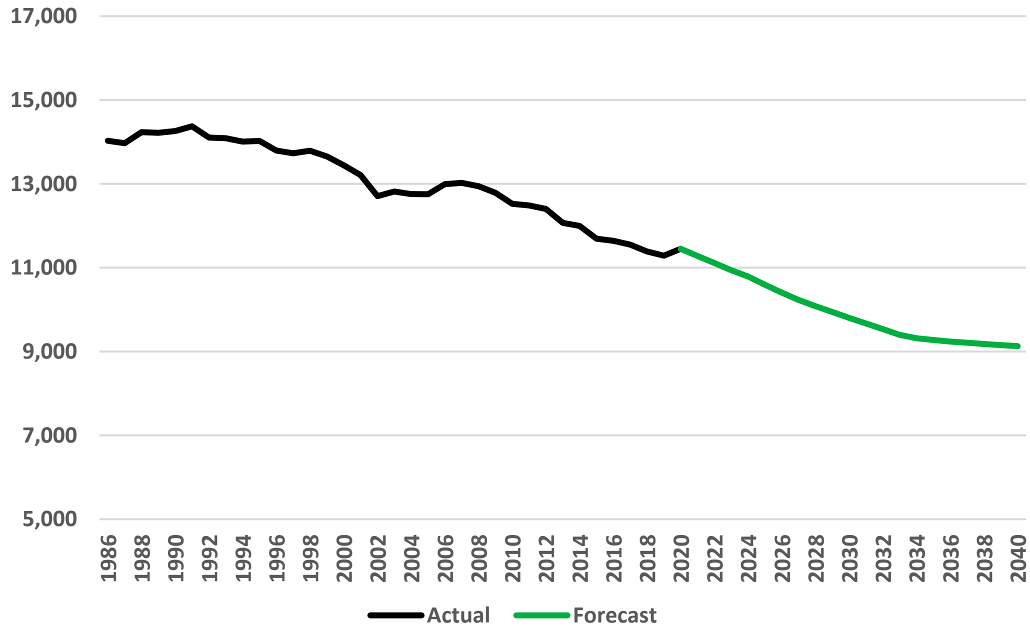

Figure 8. **Forecast residential use per customer (weather-adjusted kWh)**

Residential customer growth in Idaho Power's service area is a function of the number of new service-area households as derived from Moody's Analytics' forecast of county housing stock and demographic data. The residential-customer forecast for 2021 to 2040 shows an average annual growth rate of 1.9% as shown in Figure 9.

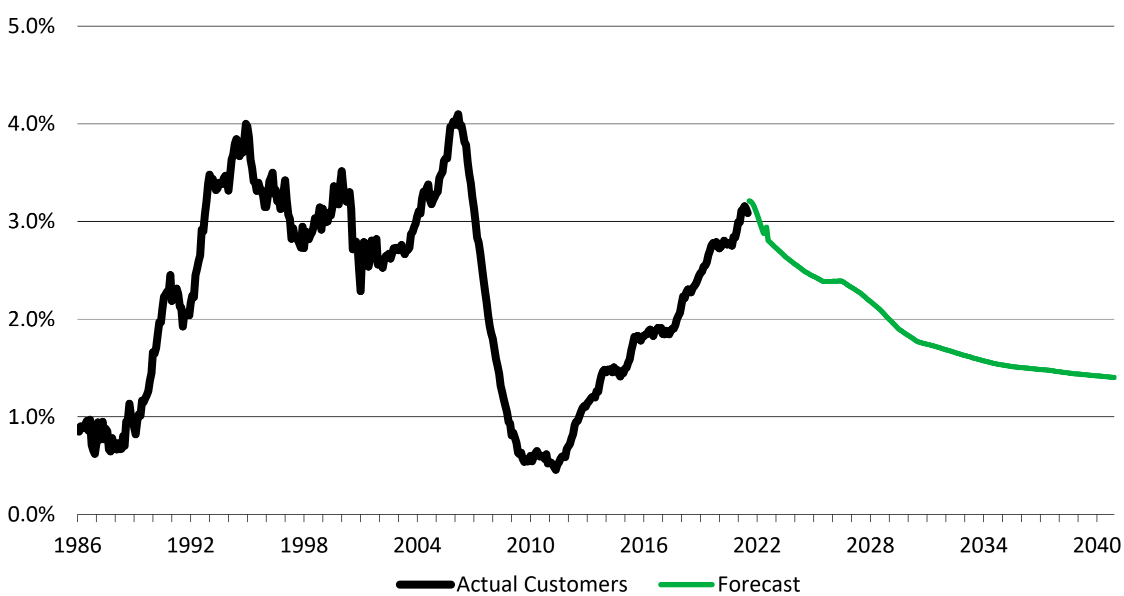

Figure 9. **Residential customer growth rates (12-month change)**

Final sales to residential retail customers can be framed in an equation that considers several factors affecting electricity sales to the residential sector. Residential sales are a function of

HDD (wintertime); CDD (summertime); historic energy efficiency trends in Idaho Power's residential customer base; saturation and replacement cycle of appliances; the number of service-area households; the real price of electricity; and the real price of natural gas to name a few. A general schematic of the forecasting methodology 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.

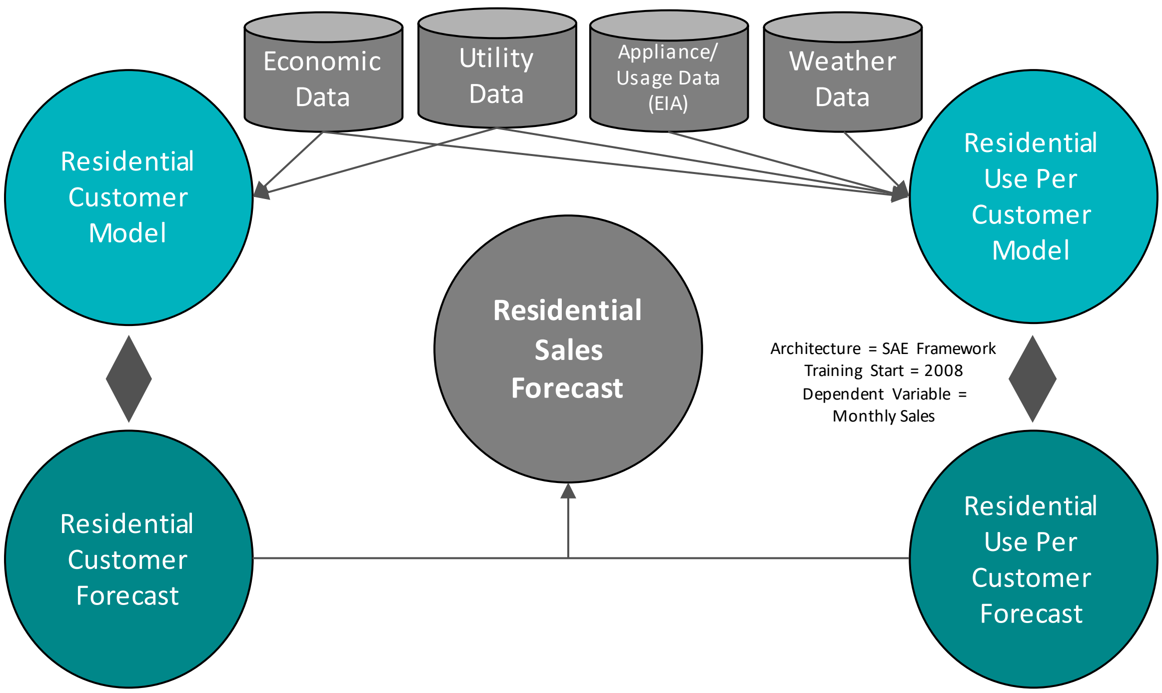

Figure 10. Residential sales forecast methodology framework

Further, 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 anticipated scenario, the commercial load is projected to increase from 475 aMW in 2021 to 564 aMW in 2040 (Table 8). The average annual compound-growth rate of the commercial load in the anticipated scenario is 0.9% during the forecast period. The commercial load in the 70th-percentile scenario is projected to increase from 481 aMW in 2021 to 572 aMW in 2040. The commercial load forecast scenarios are illustrated in Figure 11.

Table 8. Commercial load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	489	515	535	585	0.9%
70th Percentile	481	505	524	572	0.9%
Anticipated Case	475	499	517	564	0.9%

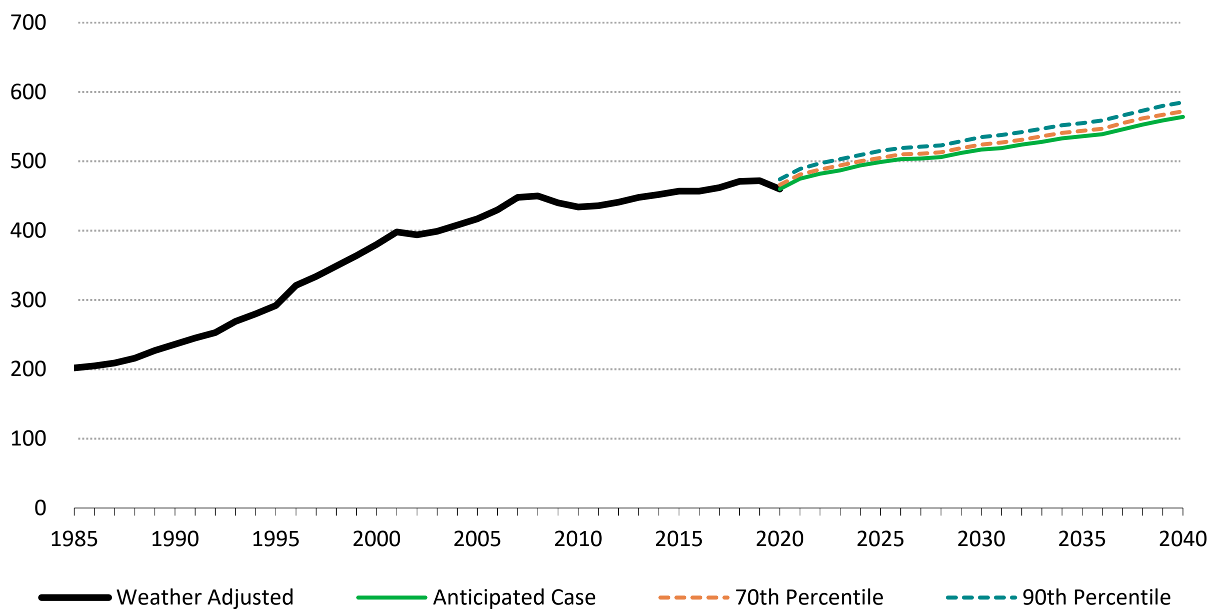

Figure 11. Forecast commercial load (aMW)

With a customer base of over 75,500, 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 2020 billed energy sales.

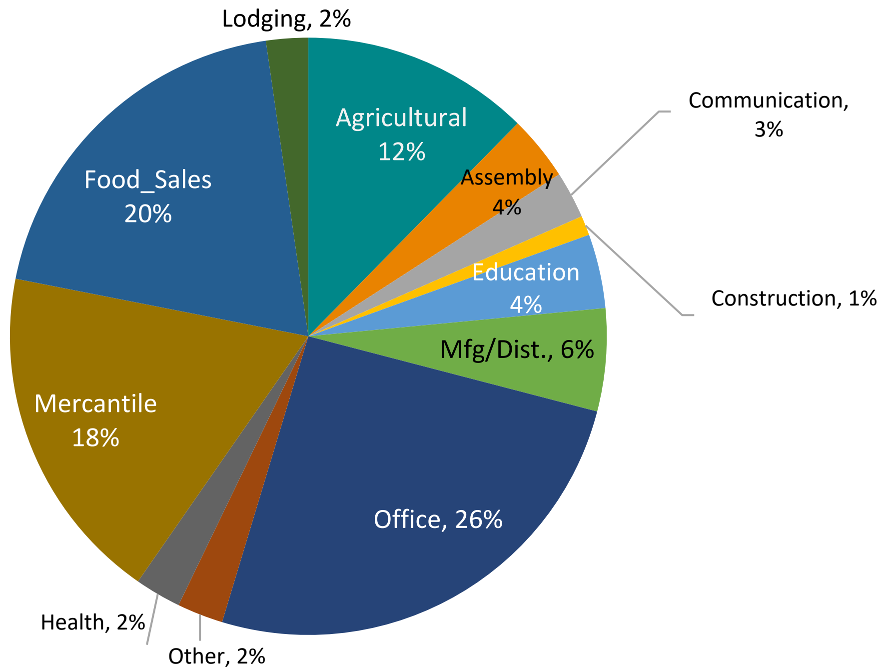

Figure 12. Commercial building share—energy bills

As indicated in Figure 12, agricultural-related, food sales, and the retail goods and service providers of the mercantile category represent nearly half of the sector. Recent trends in the sector show that mercantile growth has moderated. This moderation is primarily due to customer consolidation, growth in internet-based sales, energy efficient retrofitting, and new-construction technology implementation (particularly around lighting). Categories showing significant growth over the past 5 years are reflective of the changing profile of economic and demographic growth in the service territory. Residential growth has led to a construction boom that has seen construction energy use grow by 10% per year. Agricultural and manufacturing operations continue to migrate and flourish with growth rates of 2.2% and 2.5% respectively.

The number of commercial customers is expected to increase at an average annual rate of 1.8%, reaching approximately 107,000 customers by December 2040.

In 1990, customers in the commercial category consumed approximately 18% of Idaho Power system sales, growing to 27% by 2020. This share is forecast to remain at the upper end of this range throughout the planning period.

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

The UPC peaked in 2001 at 67,800 kWh and has declined at approximately 1.1% compounded annually to 2020. The UPC is forecast to decrease at an annual rate of 0.9% over the planning period. For this category, common elements that drive use down include a shift toward service-based over industrial customer dominance, adoption of energy efficiency technology, and electricity prices.

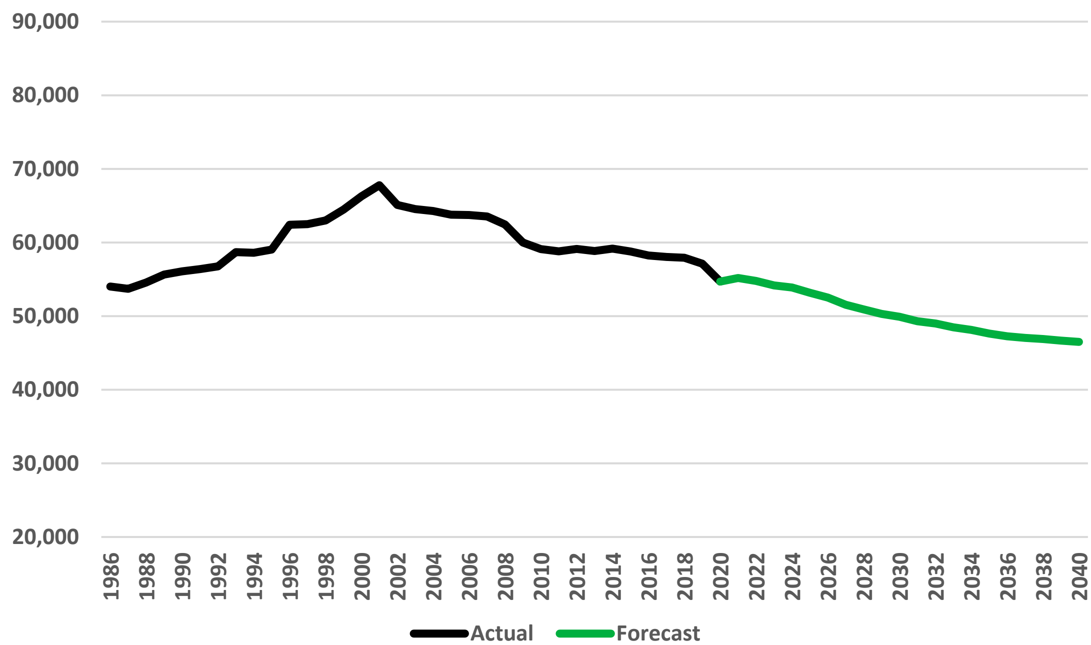

Figure 13. Forecast commercial use per customer (weather-adjusted kWh)

Figure 14 shows the diversity in the commercial segment's UPC as well as the trend for these sectors. The figure shows the 2020 UPC for each segment relative to the 2013 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. The decline in Figure 14 is also significantly exacerbated by the COVID-19 crisis, which saw many commercial customer segments close or significantly limit operations during 2020. The subsequent reduction in energy use during this period varied by segment, however they were concentrated in the service-oriented customers—particularly Education, Office, Lodging, Restaurant, and Mercantile segments. The models and independent analysis have shown a significant and ongoing rebound to normal energy use profiles in 2021 for the commercial sector. The recovery is expected to be complete by the first quarter of 2022.

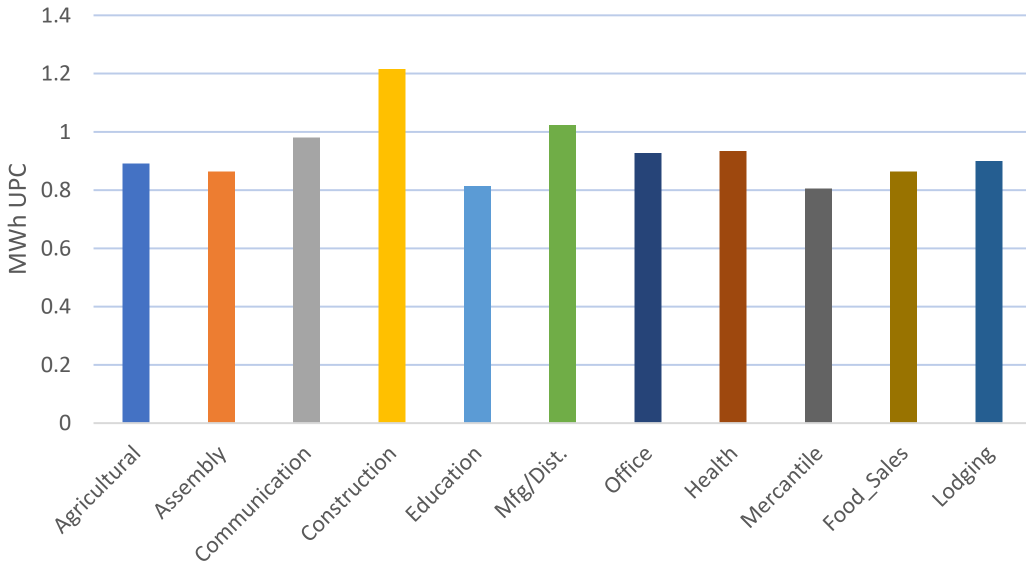

Figure 14. Commercial categories UPC, 2020 relative to 2013

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 (COVID notwithstanding) 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 that 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 2020, the number of industrial customers had risen to 123, 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 the 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 special contract customers and are addressed in the Additional Firm Load section of this document.

In the anticipated forecast, industrial load grows from 295 aMW in 2021 to 397 aMW in 2040, an average annual growth rate of 1.6% (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 70th- 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	2021	2025	2030	2040	Annual Growth Rate 2021–2040
Anticipated Case	295	332	351	397	1.6%

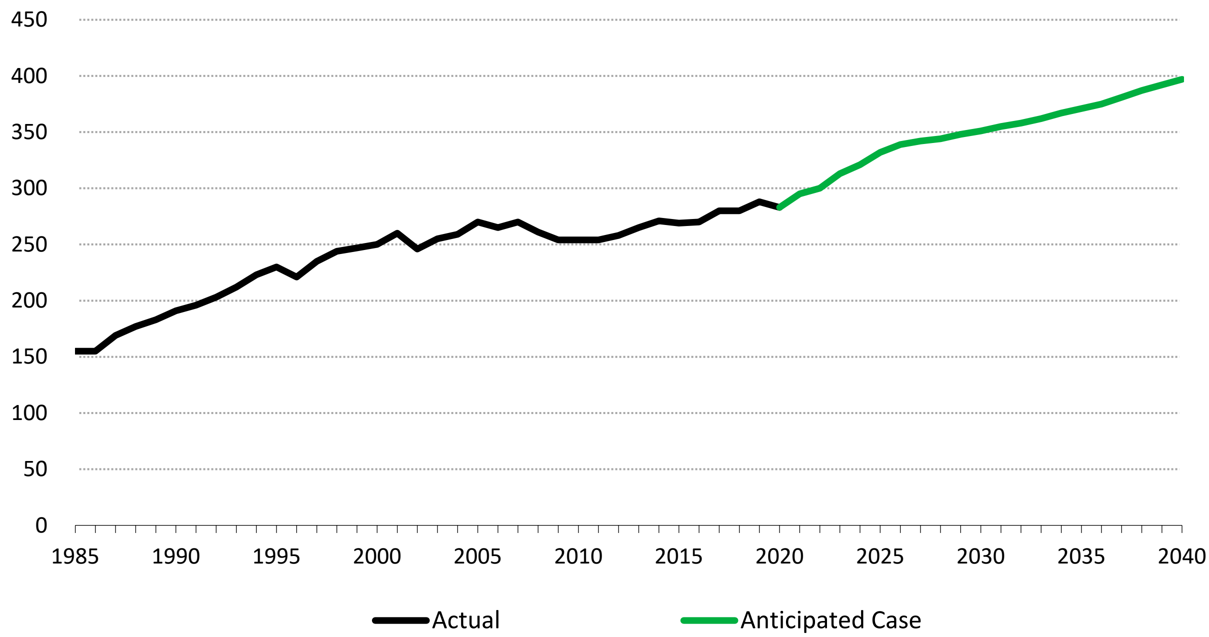

Figure 15. **Forecast industrial load (aMW)**

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

Figure 16 illustrates the 2020 share of each of the categories within the Rate 19 customers. By far, the largest share of electricity was consumed by the food manufacturing sector (38%), followed by dairy (18%) and construction-related (7%). The categorization scheme includes a range of service-providing industrial building types (assembly, lodging, mercantile, warehouse, office, education, and health care). These provide the basis for capturing, modeling, and forecasting the shifting economic landscape that influences industrial category electricity sales.

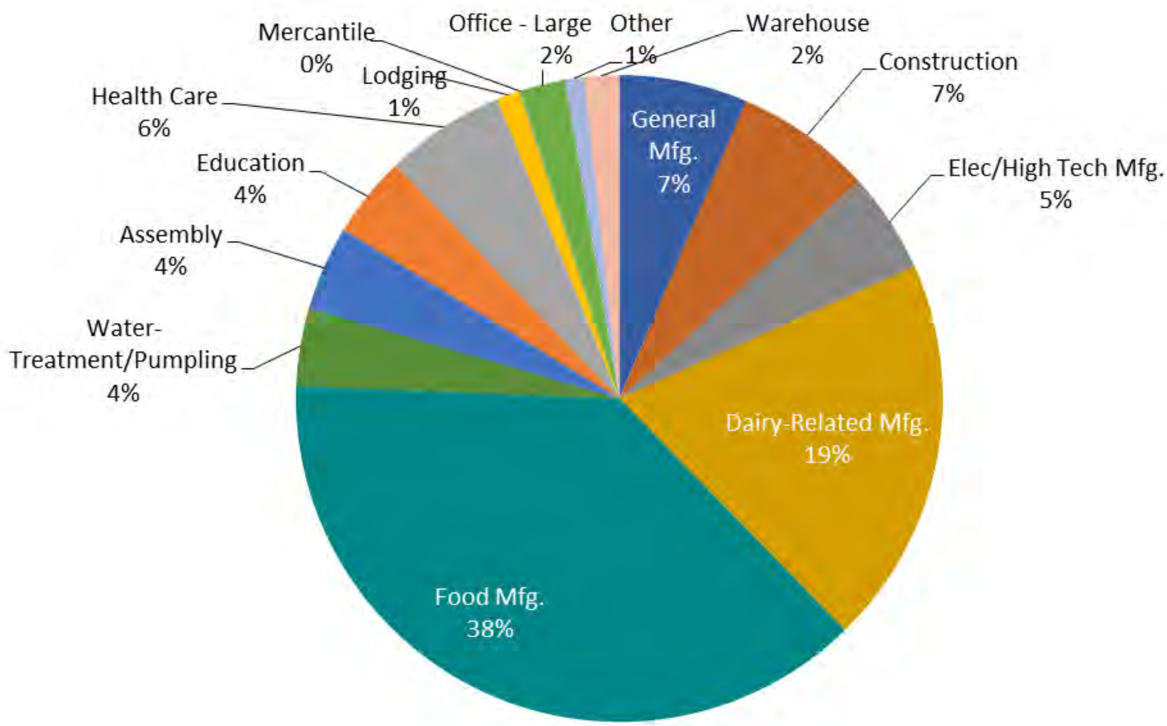

Figure 16. Industrial electricity consumption by industry group (based on 2020 sales)

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.

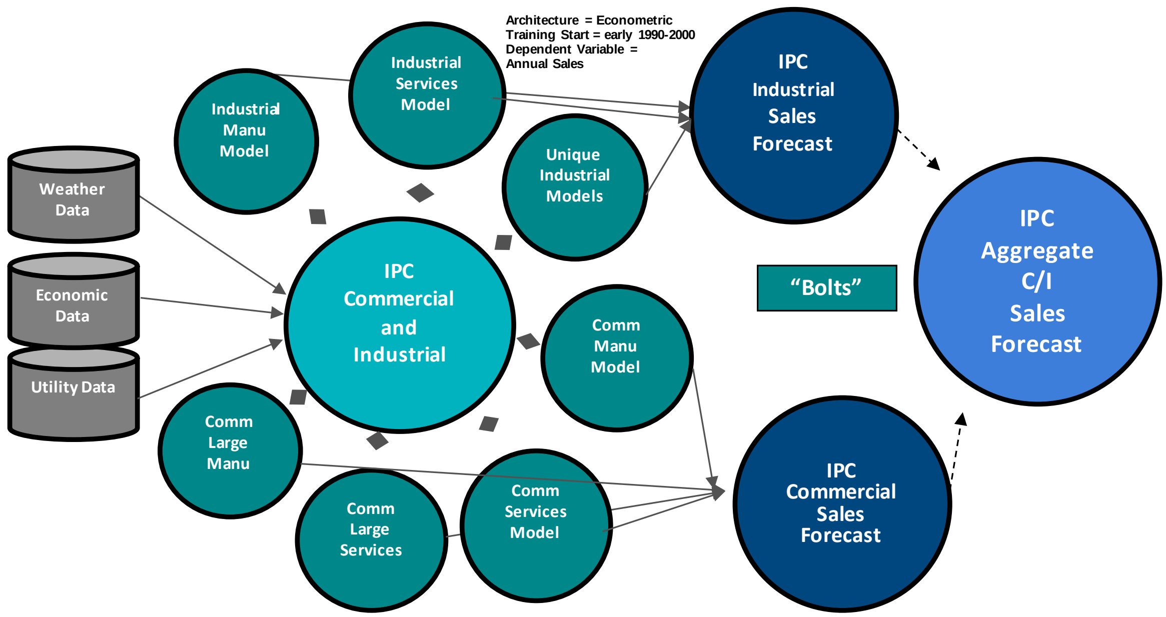

Figure 17. Commercial and industrial general sales forecast methodology

Irrigation

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

The anticipated irrigation load is forecast to increase slowly from 225 aMW in 2021 to 250 aMW in 2040, an average annual compound growth rate of 0.6%. In the 70th-percentile scenario, irrigation load is projected to be 241 aMW in 2021 and 266 aMW in 2040. The anticipated, 70th-percentile, and 90th-percentile scenarios forecast slower growth than the system in irrigation load from 2021 to 2040. The individual irrigation load forecasts are summarized in Table 10 and illustrated in Figure 18.

Table 10. Irrigation load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
90th Percentile	261	265	270	286	0.5%
70th Percentile	241	244	250	266	0.5%
Anticipated Case	225	229	234	250	0.6%

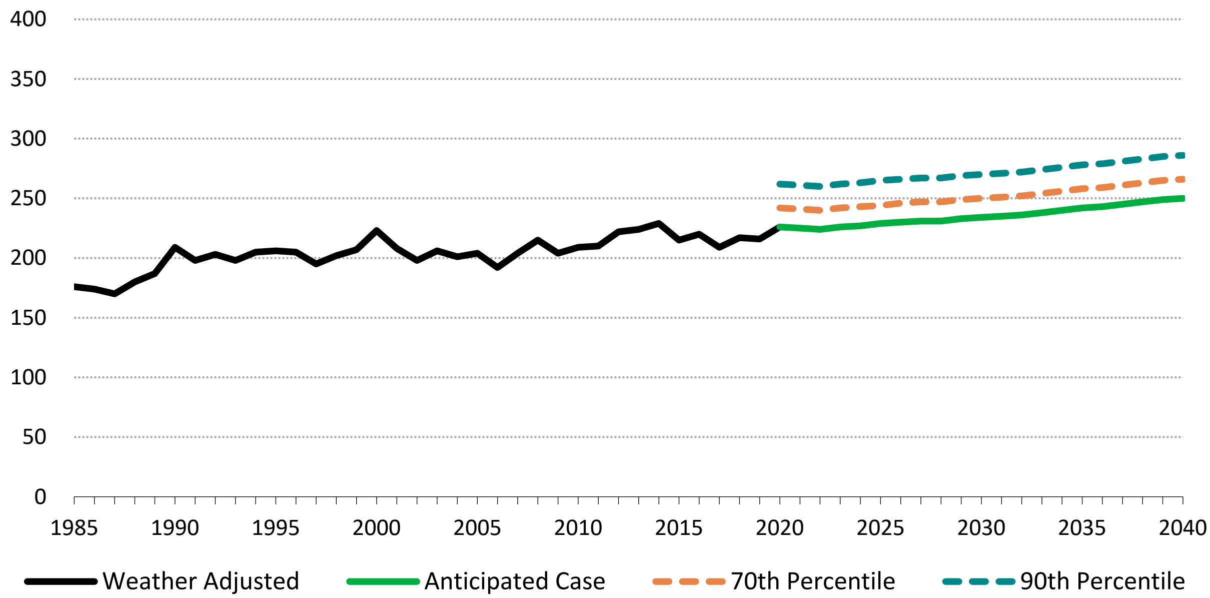

Figure 18. Forecast irrigation load (aMW)

The annual average loads in Table 10 and Figure 18 are calculated using the 8,760 hours in a typical year. In the highly seasonal irrigation sector, over 97% of the annual energy is billed during the six months from May through October, and nearly half of the annual energy is billed in just two months, July and August. During the summer, hourly irrigation loads can constitute nearly 900 MW. In a normal July, irrigation pumping accounts for roughly 25% 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 forecasted increase of sales is due to the increased customer count from the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs. Additionally, the trend toward more water intensive crops—primarily alfalfa and corn—due to growth in the dairy industry, explains most of the increased energy consumption in recent years.

The 2021 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 2020, the irrigation proportion of system sales was 13% due to the much higher relative growth in other customer classes.

Regarding customer growth, in 1980, Idaho Power had about 10,850 active irrigation accounts. By 2020, the number of active irrigation accounts had increased to 20,800 and is projected to be nearly 25,800 at the end of the planning period in 2040.

As with other sectors, average use per customer is an important consideration. Since 1988, Idaho Power has experienced growth in the number of irrigation customers but slow growth in total electricity sales (weather-adjusted) to this sector. The number of customers has increased because customers are converting previously furrow-irrigated land to sprinkler irrigated land. The conversion rate is slow and the kWh use per customer is substantially lower than the average existing Idaho Power irrigation customer. This is because water for sprinkler conversions is drawn from canals and not pumped from deep groundwater wells. In future forecasts, factors related to the conjunctive management of ground and surface water and the possible litigation associated with the resolution will require consideration. Depending on the resolution of these issues, irrigation sales may be impacted.

Additional Firm Load

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

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

In the anticipated forecast, additional firm load is expected to increase from 108 aMW in 2021 to 345 aMW in 2040, an average growth rate of 6.3% per year over the planning period (Table 11). The additional firm load energy and demand forecasts in the 70th- and 90th-percentile scenarios are identical to the anticipated-load growth scenario. The scenario of projected additional firm load is illustrated in Figure 19.

Table 11. Additional firm load growth (aMW)

Growth	2021	2025	2030	2040	Annual Growth Rate 2021–2040
Anticipated Case	108	195	345	345	6.3%

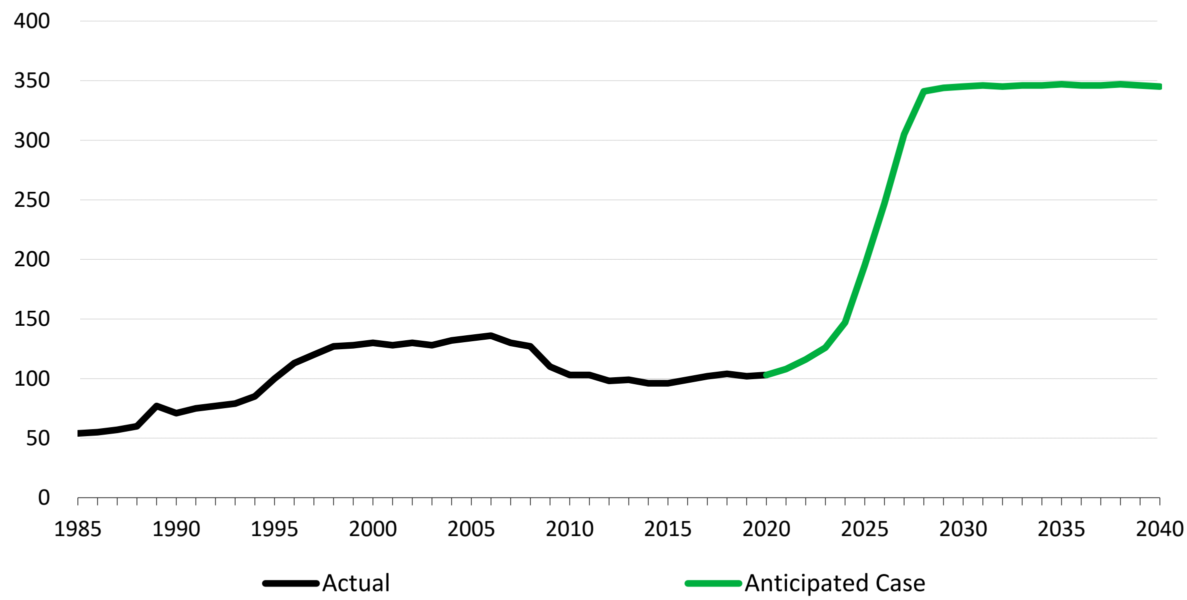

Figure 19. **Forecast additional firm load (aMW)**

Micron Technology

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

Simplot Fertilizer

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 and is the fifth largest employer in the state of Idaho with employees estimated at 4,225 workers.

Anticipated Large-Load Growth

Idaho Power's anticipated load forecast includes new large-load growth. This growth reflects industrial customers that have made a sufficient and significant binding investment and/or interest indicating a commitment of the highest probability of locating in Idaho Power's service area.

ADDITIONAL CONSIDERATIONS

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

Energy Efficiency

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

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

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

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

As discussed above, Idaho Power continuously evaluates the models for adequately capturing the impacts of energy efficiency and implements improvements when indicated. With input from DSM program managers and AEG's knowledge base, Idaho Power retains a high confidence in the representation of the impacts of energy efficiency in the forecast.

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

On-Site Generation

In recent years, the number of customers transitioning from standard to net-metering service (Schedules 6, 8, and 84) has risen dramatically, especially for residential customers. While the current population of on-site generation customers is over 1% of the population of retail customers, recent adoption of solar is relatively strong for our service area.

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

Schedules 6, 8, and 84 (net-metering) customer billing histories were compared to billing histories prior to said customer becoming a net-metering customer. The resulting average monthly impact per customer (in kWh) was then multiplied by forecasts of the Schedule 6, 8, and 84 residential, 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 use-per-customer sales impact per customer results in a monthly downward adjustment to the sales forecast for each class. At the end of the forecast period, 2040, the annual residential sales forecast reduction was about 65 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, with continued technological advancement, limiting attributes of vehicle range and refueling time continue to improve the competitiveness of these vehicles to non-electric models.

As the market grows, historical adoption data builds to provide a foundation for forecasting adoption rates and for the models to evolve. 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. However, at present, this data is only available for battery-only vehicles and data for hybrid engine-battery vehicles was not available for this forecast update. Other data sources for monitoring the outlook for PEV adoption includes the United States Department of Energy, R.L. Polk, and Moody's Analytics.

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

The evolution of the PEV market shows that high adoption continues to be evident in warmer climates, high-density and affluent population centers. The Idaho Power forecast for PEVs shows that 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

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

As supply-side resources, demand response program impacts are not incorporated into the sales and load forecast. In the load and resource balance, the forecast of existing demand response programs is subtracted from the peak-hour load forecast prior to accounting for existing supply side resources. Likewise, the performance of new demand response programs is accounted for prior to determining the need for additional supply-side resources. However, because energy efficiency programs have an impact on peak demand reduction, a component of peak hour load reduction is integrated into the sales and load forecast models. This provides a consistent treatment of both types of programs, as energy efficiency programs are considered in the sales and load forecast, while all demand response programs are included in the load and resource balance.

A thorough description of each of the energy efficiency and demand response programs is included in *Appendix B—Demand-Side Management 2020 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 (2021–2040) (average annual percent change)

	Nominal	Real*
Electricity—2021 IRP	1.0%	-1.3%
Electricity—2019 IRP	1.1%	-1.1%
Natural Gas	2.2%	0.0%

* Adjusted for inflation

Figure 20 illustrates the average electricity price paid by Idaho Power's residential customers over the historical period 1985 to 2020 and over the forecast period 2021 to 2040. Both nominal and real prices are shown. In the 2021 IRP, nominal electricity prices are expected to climb to about 12.5 cents per kWh by the end of the forecast period in 2040. Real electricity prices (inflation adjusted) are expected to decline over the forecast period at an average rate of 1.3% annually. In the 2019 IRP, nominal electricity prices were assumed to climb to about 14 cents per kWh by 2040, and real electricity prices (inflation adjusted) were expected to decline over the forecast period at an average rate of 1.1% annually.

The electricity price forecast used to prepare the sales and load forecast in the 2021 IRP reflected the additional plant investment and variable costs of integrating the resources identified in the 2019 IRP preferred portfolio. When compared to the electricity price forecast used to prepare the 2019 IRP sales and load forecast, the 2021 IRP price 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.

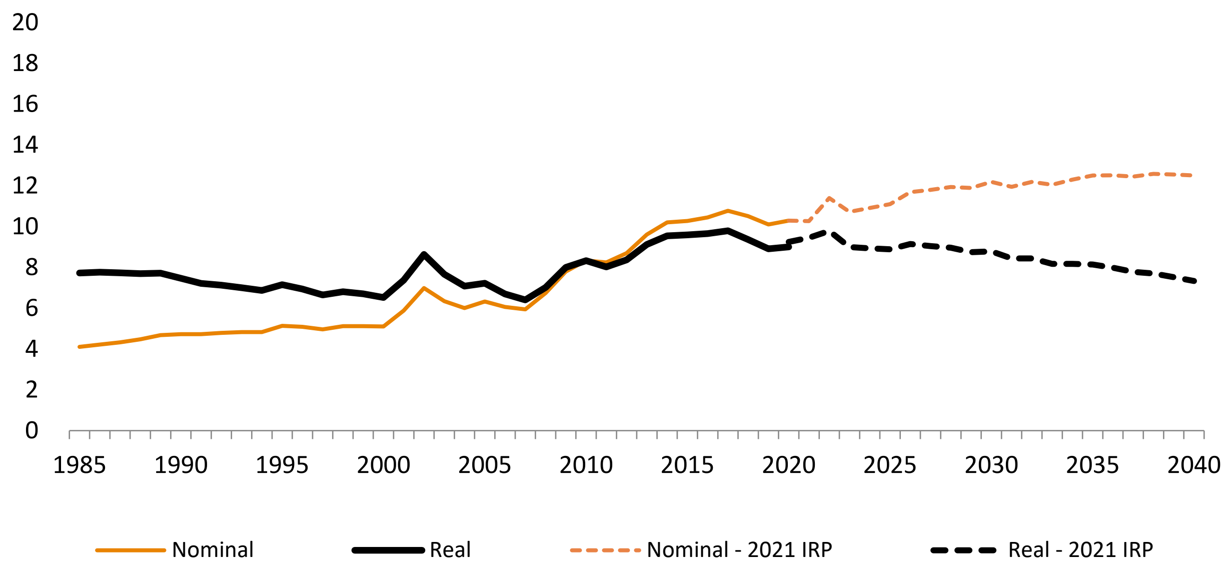

Figure 20. Forecast residential electricity prices (cents per kWh)

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 1985 to 2020 and forecast prices from 2020 to 2040. Natural gas prices remained stable and flat throughout the 1990s before moving sharply higher in 2001. After spiking in 2001, natural gas prices moved downward for a couple of years before moving sharply upward in 2004 through 2006. Since 2006, natural gas prices have declined by 47%, compared to 2020. Nominal natural gas prices are initially expected to remain relatively flat through 2022, drop in 2023, and then rise at a steady pace throughout the remainder of the forecast period, increasing 70% by 2040, growing at an average rate of 2.2% per year. Real natural gas prices (adjusted for inflation) are expected to increase over the same period at an average rate of 0% annually.

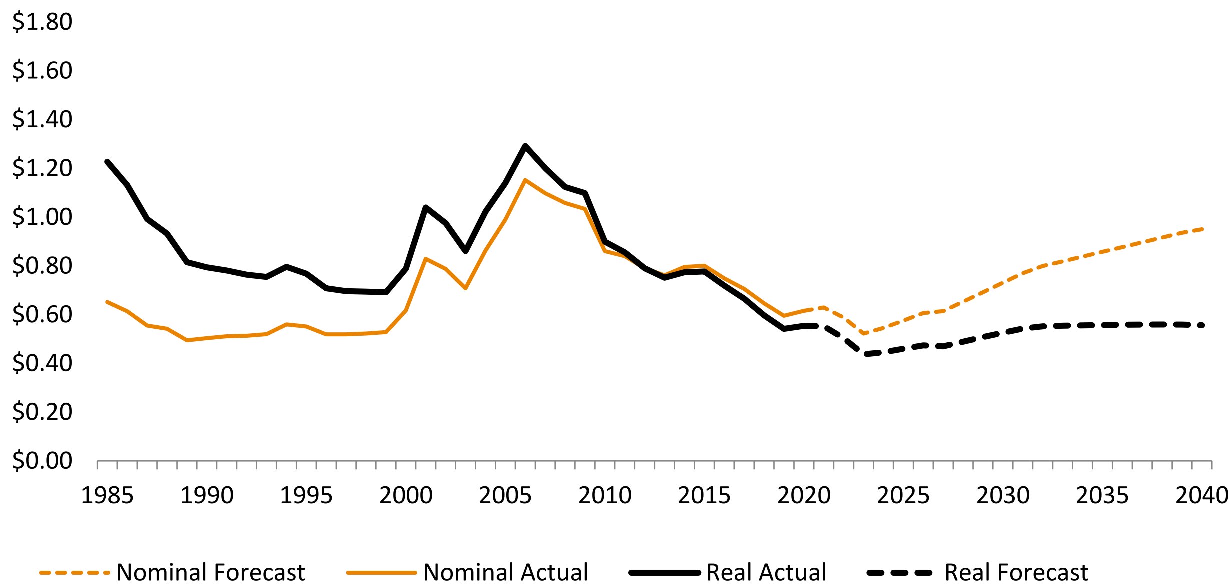

Figure 21. Forecast residential natural gas prices (dollars per therm)

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 2021 IRP price forecast, the long-term direction in real electricity prices (adjusted for inflation) is downward and the long-term projection in real natural gas prices is downward in the near term through 2023, with prices slowly rising throughout the forecast period after that.

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. A system loss study of 2012 was completed in May 2014. The results of the study concluded that on average, the revised loss coefficients were lower than those applied to generation forecasts developed prior to the 2015 IRP and were used in the development of the 2021 IRP sales and load forecast. This resulted in a one-time permanent reduction of nearly 20 aMW to the load forecast annually.

Hourly Load Forecast

As a result of stakeholder feedback and comments filed in the 2017 and 2019 IRPs, Idaho Power has leveraged several years of advanced metering infrastructure (AMI) data to adopt a new hourly load forecasting methodology to be used in the 2021 IRP. The use of AMI data expanded its footprints at Idaho Power and is utilized to inform an hourly load forecast that conforms with forecast methods mentioned throughout this document.

Historical IRP Methodology

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

2021 IRP Methodology

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

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

Enhancements to Hourly Load Forecasting

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

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

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

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

Hourly System Load Forecast Design

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

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

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

Appendix A1. Historical and Projected Sales and Load

Company System Load (excluding Astaris)

Historical Company System Sales and Load, 1980–2020 (weather adjusted)

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	7,866		974
1981	8,181	4.0%	1,014
1982	7,822	-4.4%	973
1983	8,034	2.7%	998
1984	8,120	1.1%	1,006
1985	8,262	1.7%	1,026
1986	8,346	1.0%	1,037
1987	8,489	1.7%	1,055
1988	8,832	4.0%	1,094
1989	9,203	4.2%	1,143
1990	9,575	4.0%	1,189
1991	9,749	1.8%	1,210
1992	9,973	2.3%	1,235
1993	10,268	3.0%	1,276
1994	10,676	4.0%	1,326
1995	11,140	4.4%	1,381
1996	11,479	3.0%	1,421
1997	11,770	2.5%	1,460
1998	12,261	4.2%	1,519
1999	12,558	2.4%	1,557
2000	12,951	3.1%	1,604
2001	13,089	1.1%	1,618
2002	12,791	-2.3%	1,587
2003	13,131	2.7%	1,627
2004	13,362	1.8%	1,655
2005	13,721	2.7%	1,705
2006	13,994	2.0%	1,735
2007	14,386	2.8%	1,785
2008	14,490	0.7%	1,789
2009	14,010	-3.3%	1,738
2010	13,876	-1.0%	1,720
2011	13,908	0.2%	1,724
2012	14,093	1.3%	1,742

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2013	14,101	0.1%	1,756
2014	14,283	1.3%	1,768
2015	14,131	-1.1%	1,753
2016	14,300	1.2%	1,773
2017	14,422	0.8%	1,788
2018	14,605	1.3%	1,813
2019	14,762	1.1%	1,834
2020	14,928	1.1%	1,856

Company System Load

Projected Company System Sales and Load, 2021–2040

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	15,283	2.4%	1,895
2022	15,528	1.6%	1,926
2023	15,845	2.0%	1,965
2024	16,175	2.1%	2,008
2025	16,338	1.0%	2,082
2026	16,587	1.5%	2,154
2027	16,761	1.1%	2,223
2028	16,889	0.8%	2,269
2029	16,996	0.6%	2,289
2030	17,117	0.7%	2,304
2031	17,199	0.5%	2,314
2032	17,314	0.7%	2,322
2033	17,396	0.5%	2,338
2034	17,535	0.8%	2,356
2035	17,686	0.9%	2,375
2036	17,848	0.9%	2,389
2037	18,030	1.0%	2,418
2038	18,231	1.1%	2,442
2039	18,404	0.9%	2,464
2040	18,604	1.1%	2,482

Residential Load

Historical Residential Sales and Load, 1980–2020 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	209,629		14,771	3,096		353
1981	213,579	1.9%	14,748	3,150	1.7%	355
1982	216,696	1.5%	13,562	2,939	-6.7%	337
1983	219,849	1.5%	14,321	3,149	7.1%	358
1984	222,695	1.3%	14,031	3,125	-0.8%	355
1985	225,185	1.1%	13,867	3,123	-0.1%	356
1986	227,081	0.8%	14,028	3,186	2.0%	365
1987	228,868	0.8%	13,970	3,197	0.4%	366
1988	230,771	0.8%	14,232	3,284	2.7%	375
1989	233,370	1.1%	14,217	3,318	1.0%	380
1990	238,117	2.0%	14,261	3,396	2.3%	388
1991	243,207	2.1%	14,373	3,496	2.9%	401
1992	249,767	2.7%	14,104	3,523	0.8%	401
1993	258,271	3.4%	14,088	3,638	3.3%	417
1994	267,854	3.7%	14,008	3,752	3.1%	429
1995	277,131	3.5%	14,024	3,887	3.6%	444
1996	286,227	3.3%	13,794	3,948	1.6%	451
1997	294,674	3.0%	13,728	4,045	2.5%	462
1998	303,300	2.9%	13,791	4,183	3.4%	478
1999	312,901	3.2%	13,654	4,272	2.1%	488
2000	322,402	3.0%	13,442	4,334	1.4%	494
2001	331,009	2.7%	13,210	4,373	0.9%	498
2002	339,764	2.6%	12,708	4,318	-1.3%	495
2003	349,219	2.8%	12,817	4,476	3.7%	511
2004	360,462	3.2%	12,755	4,598	2.7%	525
2005	373,602	3.6%	12,752	4,764	3.6%	547
2006	387,707	3.8%	12,992	5,037	5.7%	576
2007	397,286	2.5%	13,024	5,174	2.7%	591
2008	402,520	1.3%	12,942	5,209	0.7%	593
2009	405,144	0.7%	12,786	5,180	-0.6%	590
2010	407,551	0.6%	12,524	5,104	-1.5%	583
2011	409,786	0.5%	12,485	5,116	0.2%	583
2012	413,610	0.9%	12,403	5,130	0.3%	583
2013	418,892	1.3%	12,069	5,055	-1.5%	581
2014	425,036	1.5%	11,996	5,099	0.9%	579

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2015	432,275	1.7%	11,691	5,054	-0.9%	577
2016	440,362	1.9%	11,642	5,127	1.4%	585
2017	448,800	1.9%	11,552	5,184	1.1%	592
2018	459,128	2.3%	11,385	5,227	0.8%	596
2019	471,298	2.7%	11,287	5,320	1.8%	609
2020	484,433	2.8%	11,450	5,547	4.3%	637

Projected Residential Sales and Load, 2021–2040

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	499,559	3.1%	11,281	5,636	1.6%	644
2022	513,957	2.9%	11,110	5,710	1.3%	652
2023	527,572	2.6%	10,941	5,772	1.1%	660
2024	540,764	2.5%	10,789	5,834	1.1%	665
2025	553,746	2.4%	10,591	5,865	0.5%	670
2026	566,899	2.4%	10,405	5,898	0.6%	674
2027	579,731	2.3%	10,231	5,931	0.6%	678
2028	591,914	2.1%	10,082	5,968	0.6%	680
2029	603,243	1.9%	9,945	5,999	0.5%	685
2030	613,993	1.8%	9,803	6,019	0.3%	687
2031	624,544	1.7%	9,669	6,039	0.3%	690
2032	634,909	1.7%	9,534	6,053	0.2%	689
2033	645,083	1.6%	9,396	6,062	0.1%	692
2034	655,094	1.6%	9,319	6,105	0.7%	697
2035	665,028	1.5%	9,274	6,168	1.0%	705
2036	674,971	1.5%	9,237	6,235	1.1%	710
2037	684,927	1.5%	9,209	6,308	1.2%	721
2038	694,856	1.4%	9,180	6,379	1.1%	729
2039	704,784	1.4%	9,154	6,451	1.1%	737
2040	714,731	1.4%	9,129	6,524	1.1%	743

Commercial Load

Historical Commercial Sales and Load, 1980–2020 (weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	28,797		54,184	1,560		178
1981	29,567	2.7%	54,326	1,606	2.9%	184
1982	30,167	2.0%	54,147	1,633	1.7%	186
1983	30,776	2.0%	52,643	1,620	-0.8%	185
1984	31,554	2.5%	53,824	1,698	4.8%	194
1985	32,418	2.7%	54,495	1,767	4.0%	202
1986	33,208	2.4%	54,027	1,794	1.6%	205
1987	33,975	2.3%	53,710	1,825	1.7%	209
1988	34,723	2.2%	54,567	1,895	3.8%	216
1989	35,638	2.6%	55,654	1,983	4.7%	227
1990	36,785	3.2%	56,088	2,063	4.0%	236
1991	37,922	3.1%	56,385	2,138	3.6%	245
1992	39,022	2.9%	56,761	2,215	3.6%	253
1993	40,047	2.6%	58,693	2,350	6.1%	269
1994	41,629	4.0%	58,612	2,440	3.8%	280
1995	43,165	3.7%	59,035	2,548	4.4%	292
1996	44,995	4.2%	62,399	2,808	10.2%	321
1997	46,819	4.1%	62,490	2,926	4.2%	334
1998	48,404	3.4%	62,989	3,049	4.2%	349
1999	49,430	2.1%	64,468	3,187	4.5%	364
2000	50,117	1.4%	66,281	3,322	4.2%	380
2001	51,501	2.8%	67,783	3,491	5.1%	398
2002	52,915	2.7%	65,108	3,445	-1.3%	394
2003	54,194	2.4%	64,529	3,497	1.5%	399
2004	55,577	2.6%	64,280	3,573	2.2%	408
2005	57,145	2.8%	63,785	3,645	2.0%	417
2006	59,050	3.3%	63,731	3,763	3.2%	430
2007	61,640	4.4%	63,533	3,916	4.1%	448
2008	63,492	3.0%	62,458	3,966	1.3%	450
2009	64,151	1.0%	59,998	3,849	-2.9%	440
2010	64,421	0.4%	59,098	3,807	-1.1%	434
2011	64,921	0.8%	58,806	3,818	0.3%	436
2012	65,599	1.0%	59,128	3,879	1.6%	441
2013	66,357	1.2%	58,834	3,904	0.7%	448
2014	67,113	1.1%	59,173	3,971	1.7%	452

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2015	68,000	1.3%	58,772	3,996	0.6%	457
2016	68,883	1.3%	58,226	4,011	0.4%	457
2017	69,850	1.4%	58,031	4,053	1.1%	462
2018	71,104	1.8%	57,942	4,120	1.6%	471
2019	72,332	1.7%	57,126	4,132	0.3%	472
2020	73,703	1.9%	54,687	4,031	-2.5%	460

Projected Commercial Sales and Load, 2021–2040

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	75,289	2.2%	55,179	4,154	3.1%	475
2022	76,982	2.2%	54,790	4,218	1.5%	482
2023	78,717	2.3%	54,161	4,263	1.1%	487
2024	80,420	2.2%	53,893	4,334	1.7%	494
2025	82,123	2.1%	53,161	4,366	0.7%	499
2026	83,847	2.1%	52,530	4,404	0.9%	503
2027	85,591	2.1%	51,550	4,412	0.2%	504
2028	87,323	2.0%	50,905	4,445	0.7%	506
2029	89,008	1.9%	50,313	4,478	0.7%	512
2030	90,638	1.8%	49,915	4,524	1.0%	517
2031	92,235	1.8%	49,301	4,547	0.5%	519
2032	93,818	1.7%	49,004	4,597	1.1%	524
2033	95,394	1.7%	48,471	4,624	0.6%	528
2034	96,961	1.6%	48,127	4,666	0.9%	533
2035	98,524	1.6%	47,622	4,692	0.5%	536
2036	100,086	1.6%	47,267	4,731	0.8%	539
2037	101,652	1.6%	47,034	4,781	1.1%	546
2038	103,220	1.5%	46,896	4,841	1.2%	553
2039	104,791	1.5%	46,674	4,891	1.0%	559
2040	106,365	1.5%	46,508	4,947	1.1%	564

Irrigation Load
Historical Irrigation Sales and Load, 1980–2020 (weather adjusted)

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	10,854		160,699	1,744		199
1981	11,248	3.6%	168,950	1,900	9.0%	217
1982	11,312	0.6%	152,063	1,720	-9.5%	197
1983	11,133	-1.6%	147,885	1,646	-4.3%	188
1984	11,375	2.2%	136,181	1,549	-5.9%	176
1985	11,576	1.8%	133,372	1,544	-0.3%	176
1986	11,308	-2.3%	135,042	1,527	-1.1%	174
1987	11,254	-0.5%	132,422	1,490	-2.4%	170
1988	11,378	1.1%	138,605	1,577	5.8%	180
1989	11,957	5.1%	136,898	1,637	3.8%	187
1990	12,340	3.2%	148,190	1,829	11.7%	209
1991	12,484	1.2%	139,041	1,736	-5.1%	198
1992	12,809	2.6%	139,340	1,785	2.8%	203
1993	13,078	2.1%	132,733	1,736	-2.7%	198
1994	13,559	3.7%	132,365	1,795	3.4%	205
1995	13,679	0.9%	132,064	1,807	0.7%	206
1996	14,074	2.9%	127,939	1,801	-0.3%	205
1997	14,383	2.2%	118,804	1,709	-5.1%	195
1998	14,695	2.2%	120,611	1,772	3.7%	202
1999	14,912	1.5%	121,861	1,817	2.5%	207
2000	15,253	2.3%	128,582	1,961	7.9%	223
2001	15,522	1.8%	117,166	1,819	-7.3%	208
2002	15,840	2.0%	109,361	1,732	-4.7%	198
2003	16,020	1.1%	112,556	1,803	4.1%	206
2004	16,297	1.7%	108,438	1,767	-2.0%	201
2005	16,936	3.9%	105,450	1,786	1.1%	204
2006	17,062	0.7%	98,468	1,680	-5.9%	192
2007	17,001	-0.4%	105,169	1,788	6.4%	204
2008	17,428	2.5%	108,589	1,892	5.8%	215
2009	17,708	1.6%	101,150	1,791	-5.4%	204
2010	17,846	0.8%	102,345	1,826	2.0%	209

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2011	18,292	2.5%	100,456	1,838	0.6%	210
2012	18,675	2.1%	104,483	1,951	6.2%	222
2013	19,017	1.8%	103,133	1,961	0.5%	224
2014	19,328	1.6%	103,920	2,009	2.4%	229
2015	19,756	2.2%	95,126	1,879	-6.4%	215
2016	20,042	1.4%	96,382	1,932	2.8%	220
2017	20,246	1.0%	90,552	1,833	-5.1%	209
2018	20,459	1.1%	92,940	1,901	3.7%	217
2019	20,566	0.5%	92,107	1,894	-0.4%	216
2020	20,804	1.2%	95,385	1,984	4.8%	226

Projected Irrigation Sales and Load, 2021–2040

Year	Maximum Active Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	21,063	1.2%	93,540	1,970	-0.7%	225
2022	21,290	1.1%	92,318	1,965	-0.2%	224
2023	21,538	1.2%	92,090	1,983	0.9%	226
2024	21,786	1.2%	91,540	1,994	0.5%	227
2025	22,035	1.1%	90,887	2,003	0.4%	229
2026	22,283	1.1%	90,320	2,013	0.5%	230
2027	22,531	1.1%	89,780	2,023	0.5%	231
2028	22,782	1.1%	89,216	2,033	0.5%	231
2029	23,028	1.1%	88,648	2,041	0.4%	233
2030	23,278	1.1%	88,097	2,051	0.5%	234
2031	23,527	1.1%	87,552	2,060	0.4%	235
2032	23,774	1.0%	87,170	2,072	0.6%	236
2033	24,024	1.1%	86,879	2,087	0.7%	238
2034	24,274	1.0%	86,599	2,102	0.7%	240
2035	24,522	1.0%	86,333	2,117	0.7%	242
2036	24,770	1.0%	86,082	2,132	0.7%	243
2037	25,020	1.0%	85,852	2,148	0.7%	245
2038	25,267	1.0%	85,634	2,164	0.7%	247
2039	25,515	1.0%	85,457	2,180	0.8%	249
2040	25,763	1.0%	85,311	2,198	0.8%	250

Industrial Load

Historical Industrial Sales and Load, 1980–2020 (not weather adjusted)

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	112		9,894,706	1,106		125
1981	118	5.7%	9,718,723	1,148	3.9%	132
1982	122	3.5%	9,504,283	1,162	1.2%	133
1983	122	-0.3%	9,797,522	1,194	2.7%	138
1984	124	1.5%	10,369,789	1,282	7.4%	147
1985	125	1.2%	10,844,888	1,357	5.9%	155
1986	129	2.7%	10,550,145	1,357	-0.1%	155

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1987	134	4.1%	11,006,455	1,474	8.7%	169
1988	133	-1.0%	11,660,183	1,546	4.9%	177
1989	132	-0.6%	12,091,482	1,594	3.1%	183
1990	132	0.2%	12,584,200	1,662	4.3%	191
1991	135	2.5%	12,699,665	1,719	3.4%	196
1992	140	3.4%	12,650,945	1,770	3.0%	203
1993	141	0.5%	13,179,585	1,854	4.7%	212
1994	143	1.7%	13,616,608	1,948	5.1%	223
1995	120	-15.9%	16,793,437	2,021	3.7%	230
1996	103	-14.4%	18,774,093	1,934	-4.3%	221
1997	106	2.7%	19,309,504	2,042	5.6%	235
1998	111	4.6%	19,378,734	2,145	5.0%	244
1999	108	-2.3%	19,985,029	2,160	0.7%	247
2000	107	-0.8%	20,433,299	2,191	1.5%	250
2001	111	3.5%	20,618,361	2,289	4.4%	260
2002	111	-0.1%	19,441,876	2,156	-5.8%	246
2003	112	1.0%	19,950,866	2,234	3.6%	255
2004	117	4.3%	19,417,310	2,269	1.5%	259
2005	126	7.9%	18,645,220	2,351	3.6%	270
2006	127	1.0%	18,255,385	2,325	-1.1%	265
2007	123	-3.6%	19,275,551	2,366	1.8%	270
2008	119	-3.1%	19,412,391	2,308	-2.4%	261
2009	124	4.0%	17,987,570	2,224	-3.6%	254
2010	121	-2.0%	18,404,875	2,232	0.3%	254
2011	120	-1.1%	18,597,050	2,230	-0.1%	254
2012	115	-4.2%	19,757,921	2,271	1.8%	258
2013	114	-0.7%	20,281,837	2,314	1.9%	265
2014	113	-0.7%	20,863,653	2,363	2.1%	271
2015	116	2.8%	20,271,082	2,360	-0.1%	269
2016	118	1.4%	19,993,955	2,361	0.0%	270
2017	117	-1.1%	20,996,425	2,453	3.9%	280
2018	115	-1.6%	21,274,929	2,447	-0.3%	280
2019	124	8.0%	20,288,866	2,521	3.0%	288

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2020	124	-0.3%	19,912,671	2,466	-2.2%	283

Projected Industrial Sales and Load, 2021–2040

Year	Average Customers	Percent Change	kWh per Customer	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	124	-0.2%	20,879,623	2,580	4.6%	295
2022	123	-0.5%	21,326,834	2,623	1.7%	300
2023	123	0.0%	22,198,824	2,730	4.1%	313
2024	125	1.6%	22,532,633	2,817	3.2%	321
2025	126	0.8%	22,993,784	2,897	2.9%	332
2026	126	0.0%	23,539,107	2,966	2.4%	339
2027	126	0.0%	23,746,821	2,992	0.9%	342
2028	129	2.4%	23,388,087	3,017	0.8%	344
2029	130	0.8%	23,420,860	3,045	0.9%	348
2030	130	0.0%	23,653,746	3,075	1.0%	351
2031	130	0.0%	23,868,001	3,103	0.9%	355
2032	132	1.5%	23,787,633	3,140	1.2%	358
2033	133	0.8%	23,849,695	3,172	1.0%	362
2034	133	0.0%	24,135,122	3,210	1.2%	367
2035	133	0.0%	24,409,273	3,246	1.1%	371
2036	135	1.5%	24,355,460	3,288	1.3%	375
2037	135	0.0%	24,705,719	3,335	1.4%	381
2038	135	0.0%	25,098,479	3,388	1.6%	387
2039	135	0.0%	25,405,447	3,430	1.2%	392
2040	137	1.5%	25,425,088	3,483	1.6%	397

Additional Firm Sales and Load
Historical Additional Firm Sales and Load, 1980–2020

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
1980	360		41
1981	376	4.6%	43
1982	367	-2.4%	42
1983	425	15.7%	49
1984	466	9.7%	53
1985	471	1.1%	54
1986	482	2.4%	55
1987	502	4.2%	57
1988	530	5.6%	60
1989	671	26.5%	77
1990	625	-6.9%	71
1991	661	5.8%	75
1992	680	2.9%	77
1993	689	1.3%	79
1994	740	7.5%	85
1995	878	18.6%	100
1996	989	12.6%	113
1997	1,048	6.0%	120
1998	1,113	6.2%	127
1999	1,121	0.8%	128
2000	1,143	1.9%	130
2001	1,118	-2.1%	128
2002	1,139	1.9%	130
2003	1,120	-1.7%	128
2004	1,156	3.3%	132
2005	1,175	1.6%	134
2006	1,189	1.2%	136
2007	1,141	-4.0%	130
2008	1,114	-2.4%	127
2009	965	-13.4%	110
2010	907	-6.0%	103
2011	906	0.0%	103
2012	862	-4.8%	98
2013	867	0.5%	99
2014	841	-2.9%	96

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2015	842	0.1%	96
2016	870	3.3%	99
2017	897	3.1%	102
2018	910	1.4%	104
2019	895	-1.7%	102
2020	900	0.6%	103

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

Projected Additional Firm Sales and Load, 2021–2040

Year	Billed Sales (thousands of MWh)	Percent Change	Average Load (aMW)
2021	943	4.7%	108
2022	1,019	8.1%	116
2023	1,104	8.4%	126
2024	1,288	16.7%	147
2025	1,706	32.4%	195
2026	2,163	26.8%	247
2027	2,668	23.3%	305
2028	2,996	12.3%	341
2029	3,010	0.4%	344
2030	3,025	0.5%	345
2031	3,027	0.1%	346
2032	3,032	0.2%	345
2033	3,028	-0.1%	346
2034	3,029	0.0%	346
2035	3,040	0.4%	347
2036	3,043	0.1%	346
2037	3,035	-0.3%	346
2038	3,036	0.0%	347
2039	3,028	-0.3%	346
2040	3,032	0.1%	345

*Includes Micron Technology, Simplot Fertilizer, the INL, and any anticipated special contract customers