Intermountain Gas Company

Integrated Resource Plan

2019 – 2023

October 2019

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Overview

Executive Summary

Natural gas continues to be the fuel of choice in Idaho. Southern Idaho's manufacturing plants, commercial businesses, new homes and electric power peaking plants, all rely on natural gas to provide an economic, efficient, environmentally friendly, comfortable form of heating energy. Intermountain Gas Company (Intermountain, IGC, or Company) endorses and encourages the wise and efficient use of energy in general and, in particular, natural gas for high efficient uses in Idaho and Intermountain's service area.

Forecasting the demand of Intermountain's growing customer base is a regular part of Intermountain's operations, as is determining how to best meet the load requirements brought on by this demand. Public input is an integral part of this planning process. The demand forecasting and resource decision making process is ongoing. This Integrated Resource Plan (IRP) document represents a snapshot in time similar to a balance sheet. It is not meant to be a prescription for all future energy resource decisions, as conditions will change over the planning horizon impacting areas covered by this plan. Rather, this document is meant to describe the currently anticipated conditions over the five-year planning horizon, the anticipated resource selections and the process for making resource decisions. The planning process described herein is an integral part of Intermountain's ongoing commitment to make the wise and efficient use of natural gas an important part of Idaho's energy future.

About the Company

Intermountain Gas, a subsidiary of MDU Resources Group, Inc., is a natural gas local distribution company that was founded in 1950. The Company served its first customer in 1956. Intermountain is the sole distributor of natural gas in southern Idaho. Its service area extends across the entire breadth of southern Idaho, an area of 50,000 square miles, with a population of roughly 1,344,000. At the end of 2018, Intermountain served 364,512 customers in 75 communities through a system of over 12,800 miles of transmission, distribution and service lines. In 2018, over 720 million therms were delivered to customers and over 300 miles of transmission, distribution and service lines were added to accommodate new customer additions and maintain service for Intermountain’s growing customer base.

Customer Base

The economy of Intermountain’s service area is based primarily on agriculture and related industries. Major crops are potatoes, milk and sugar beets. Major agricultural-related industries include food processing and production of chemical fertilizers. Other significant industries are electronics, general manufacturing and services and tourism.

Intermountain provides natural gas sales and service to two major markets: the residential/commercial market and the large volume market. The Company’s residential and commercial customers use natural gas primarily for space and water heating. Intermountain’s large volume customers transport natural gas through Intermountain's system to be used for boiler and manufacturing applications. Large volume demand for natural gas is strongly influenced by the agricultural economy and the price of alternative fuels. During 2018, 50% of the throughput on Intermountain's system was attributable to large volume sales and transportation.

The IRP Process

Intermountain's Integrated Resource Plan is assembled by a talented cross-functional team from various departments within the Company. This five-year forecast is continually updated within the Company and filed with the Commission every two years. It helps to ensure that Intermountain will be able to continue to provide safe and reliable service while minimizing energy costs. The IRP considers all available resources to meet the needs of Intermountain's customers on a consistent and comparable basis. A high-level overview of the process is described below. Each step in the process will be outlined in greater detail in later sections of this document.

Demand

As a starting point, Intermountain develops base case, high growth, and low growth scenarios to project the customer demand on its system.

For the core market, the first step involves forecasting customer growth for both residential and commercial customers. Next, Intermountain develops design weather. Then the Company determines the core market usage per customer using historical usage, weather and geographic data. The usage per customer number is then applied to the customer forecast under design weather conditions to determine the core market demand.

To forecast both therm usage and contract demand for large volume customers, the Company analyzes historical usage, economic trends, and direct input from large volume customers. This approach is appropriate given the small population size of these customer classes. Because large volume customers typically use natural gas for industrial processes, weather data is not generally considered.

Both core market and large volume demand forecasts are developed by areas of interest (AOI) and then aggregated to provide a Total Company perspective. Analyzing demand by AOI allows the Company to consider factors specifically related to a geographic area when considering potential capacity enhancements.

Supply & Delivery Resources

After determining customer demand for the five-year period, the Company identifies and reviews currently available supply and capacity resources. Additionally, the Company includes in its resource portfolio analysis various non-traditional resources as well as potential savings resulting from its energy efficiency program.

Optimization

The final step in the development of the IRP is the optimization modeling process which matches demand against supply and deliverability resources by AOI and for the entire Company to identify any potential deficits. Potential capacity enhancements are then analyzed to identify the most cost effective and operationally practical option to address potential deficits. The Planning Results Section shows how all deficits will be met over the planning horizon of the study.

Intermountain Gas Resource Advisory Committee

To enhance the Integrated Resource Plan development, the Company established the Intermountain Gas Resource Advisory Committee (IGRAC). The intent of the committee is to provide a forum through which public participation can occur as the IRP is developed.

Advisory committee members were solicited from across Intermountain's service territory as representatives of the communities served by Intermountain. Exhibit 1, Section A, is a sample of the initial invitation to join the committee. Committee members have varied backgrounds in regulation, economic development, and business. A full listing of IGRAC members is included in Exhibit 1, Section A.

Intermountain held meetings across its service territory to ensure travel would not impact the ability of committee members and the public to participate. Three meetings were held during the IRP process at the following locations: Boise, Twin Falls, and Idaho Falls. Included in Exhibit 1, Section B and C are sample invitations, sign in sheets and agendas from the meetings, along with copies of the presentations.

After each meeting, for members who were unable to attend, an email containing the materials covered was sent out. The Company provided a comment period after each meeting to ensure feedback was timely and could be incorporated into the IRP. Intermountain also established an email account where feedback and information requests could be managed.

Summary

Through the process explained above, Intermountain analyzed residential, commercial and large volume demand growth and its consequent impact on Intermountain's distribution system using design weather conditions under various scenarios. Forecast demand under each of the customer growth scenarios was measured against the available natural gas delivery systems to project the magnitude and timing of potential delivery deficits, both from a total Company perspective as well as an AOI perspective. The resources needed to meet these projected deficits were analyzed within a framework of traditional, non-traditional and energy efficiency options to determine the most cost effective and operationally practical means available to manage the deficits. In utilizing these options, Intermountain's core market and firm transportation customers can continue to rely on uninterrupted firm service both now and in the future.

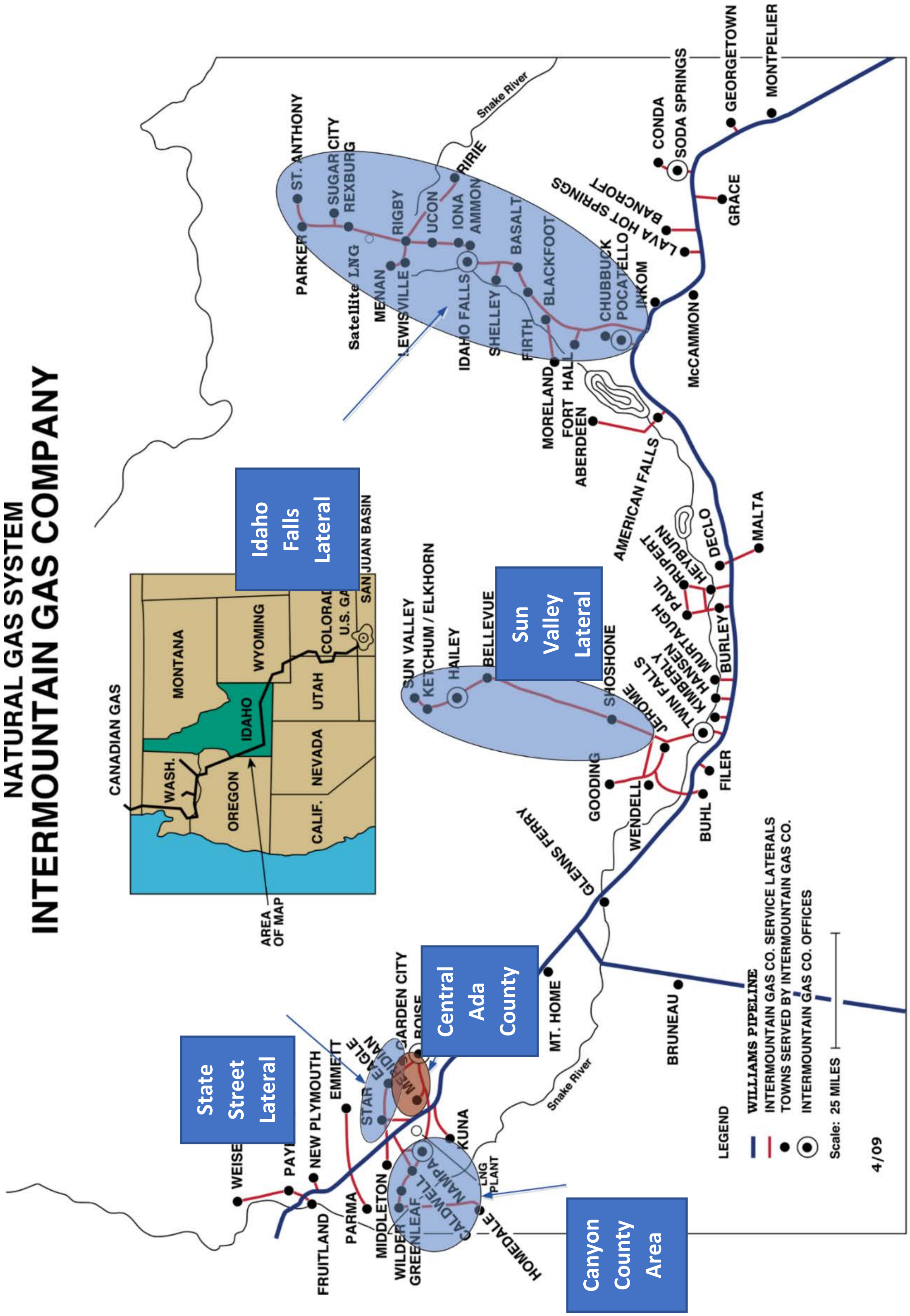


Figure 1: Intermountain Gas System Map

About the Natural Gas Industry

Natural Gas and the National Energy Picture

The blue flame. Curling up next to a natural gas fireplace, starting the morning with a hot shower, coming home to a warm house. The blue flame of natural gas represents warmth and comfort, and provides warmth and comfort in the cleanest, safest, most affordable way possible.

Natural gas is the cleanest fossil fuel. Natural gas burns efficiently, producing primarily heat and water vapor. The Northwest Gas Association has reported that natural gas produces about 45% less carbon dioxide than burning coal, 30% less than oil and 15% less than wood. In addition, according to the American Gas Association, households with natural gas versus all electric appliances produce 41% less greenhouse gas emissions.

Natural gas is the safest form of energy. According to the Department of Transportation, pipelines are the safest form of energy transportation.

Natural gas is affordable. Over the last decade, the price of natural gas fell by about 37% (adjusted for inflation). According to the Northwest Gas Association, households that use natural gas for heating, cooking and clothes drying spend an average of $874 less per year than homes using electricity for those same applications. The American Gas Association has reported that for residential customers, the cost of natural gas has been lower than the cost of propane, fuel oil, or electricity since 2010, and is forecasted to stay low through 2040.

Consumers benefit from the use of natural gas in two ways: directly and indirectly. Using natural gas to warm your home, heat your water, cook your meal, dry your clothes or fuel your fireplace, is the direct use of natural gas. The Northwest Gas Association has reported that the direct use of natural gas is about 92% efficient.

According to the American Gas Association, in the United States natural gas currently meets more than 25% of the nation’s energy needs, providing energy to more than 75 million residential, commercial and industrial customers. The residential market is comprised of approximately 69 million homes and represents 18% of total U.S. natural gas consumption. Approximately 5.5 million commercial customers make up 13% of total U.S. natural gas consumption. Roughly 185,400 industrial and manufacturing sector customers use natural gas in their processes, consuming 32% of the U.S. annual total.

Consumers also benefit from the use of natural gas in a much less obvious way through the indirect use of natural gas. The most common application of indirect use is using natural gas for electric generation. According to the Northwest Gas Association, as much as 35% of the natural gas end use market is for electric generation. The indirect us of natural gas is less efficient than direct use as it provides only 32% of the energy as heat by the time it reaches a customer’s home or business. However, the U.S. Energy Information Administration (EIA) has reported that natural gas used for electric generation has allowed U.S. power plants to achieve a 27-year low in emissions. In fact, according to the Northwest Gas Association, natural gas emits up to 56% fewer greenhouse gasses than coal for the same amount of electricity.

Natural gas is now even more plentiful in North America, with an estimated 100 years supply at current consumption levels. Even with this plentiful supply, and lower, more stable prices, it remains vital that all natural gas customers use the energy as wisely and as efficiently as possible.

The Direct Use of Natural Gas

The direct use of natural gas refers to employing natural gas at the end-use point for space heating, water heating, and other applications, as opposed to using natural gas to generate electricity to be transmitted to the end-use point and then employed for space or water heating. As discussed earlier, the direct use of natural gas achieves 92% energy efficiency and makes economic sense in today's energy era.

As electric generating capacity becomes more constrained in the Pacific Northwest, additional peak generating capacity will primarily be natural gas fired. Direct use will mitigate the need for future generating capacity. If more homes and business use natural gas for heating and commercial applications, then the need for additional generating resources will be reduced. At times of excess capacity, water storage normally used for generating power, can be released for additional irrigating, aquifer recharging, fish migration, and navigation uses.

From a resource and environmental perspective, the direct use of natural gas makes the most sense. More energy is delivered using the same amount of natural gas, resulting in lower cost and lower CO_2 emissions. This direct, and therefore, more efficient natural gas usage will serve to keep natural gas prices, as well as electricity prices, lower in the future.

Intermountain plays a critical role in providing energy throughout southern Idaho. The Company has approximately 330,000 residential customers which use roughly 165.6 million therms a year for space heating. If this demand had to be served by electricity, it would mean that Intermountain's residential customers would require approximately 3,787,069 megawatt hours a year to replace the natural gas currently used to heat their homes.

According to its 2018 Annual Report, Idaho Power's total annual residential megawatt hour sales for 2018 were 5,135,000. If the aforementioned 330,000 residential customers used electric space heat instead of natural gas, Idaho Power's total residential sendout would rise to 8,922,069 mWh, a 73.8% increase, requiring considerable additional generation and transmission facilities.

In peak terms, if these 330,000 customers had electric furnaces with 25kw capacity, and just 1/3 of them were operating simultaneously during a cold-weather winter peak, there would be an additional winter peak load of 2,750 megawatts. According to Idaho Power's Annual Report, it recently experienced a January 2017 winter peak load of 2,527 megawatts. Without the direct use of natural gas to heat these 330,000 homes, Idaho Power's winter peak load could reach 5,277 megawatts, a 109% increase! This additional 2,750-megawatt peak load would be the equivalent of approximately nine 300-megawatt natural gas-fired electric generating facilities, like Langley Gulch, all running at full capacity. A substantial increase in transmission facilities would also be required to handle this peak load, since it would be well above the Idaho Power record Summer peak from July 2017 of 3,422 megawatts.

Ultimately, promoting and using natural gas for direct use in heating applications is the best use of the resource, and mitigates the need for costly generation and infrastructure expansion across the U.S. electric grid.

Demand

Demand Forecast Overview

The first step in resource planning is forecasting future load requirements. Three essential components of the load forecast include projecting the number of customers requiring service, forecasting the weather sensitive customers' response to temperatures and estimating the weather those customers may experience. To complete the demand forecast, contracted maximum deliveries to industrial customers are also included.

Intermountain's long range demand forecast incorporates various factors including divergent customer forecasts, statistically based gas usage per customer calculations, varied weather profiles and banded natural gas price projections; all of which are discussed later in this document. Using various combinations of these factors results in six separate and diverse demand forecast scenarios for the weather sensitive core market customers.

Combining those projections with the large volume market forecast provides Intermountain with six total company demand scenarios that envelop a wide range of potential outcomes. These forecasts not only project monthly and annual loads but also predict daily usage including peak demand events. The inclusion of all this detail allows Intermountain to evaluate the adequacy of its supply arrangements and delivery under a wide range of demand scenarios.

Intermountain's resource planning looks at distinct segments (i.e. AOIs) within its current distribution system. After analyzing resource requirements at the segment level, the data is aggregated to provide a Total Company perspective. The AOIs for planning purposes are as follows:

- The Canyon County Area (CCA), which serves core market customers in Canyon County.
- The Sun Valley Lateral (SVL), which serves core market customers in Blaine and Lincoln counties.
- The Idaho Falls Lateral (IFL), which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties.
- The Central Ada County (CAC), which serves core market customers in the area of Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west.
- The State Street Lateral (SSL), which serves core market customers in the area of Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21.
- The All Other segment, which serves core market customers in Ada County not included in the State Street Lateral and Central Ada Area, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington counties.

Residential & Commercial Customer Growth Forecast

This section of Intermountain's IRP describes and summarizes the residential and commercial customer growth forecast for the years 2019 through 2023. This forecast provides the anticipated magnitude and direction of Intermountain's residential and commercial customer growth by the identified Areas of Interest for Intermountain's current service territory. Customer growth is the primary driving factor in IGC's five-year demand forecast contained within this IRP.

IGC's customer growth forecast includes three key components:

1. Residential new construction customers,
2. Residential customers who convert to natural gas from an alternative fuel, and
3. Commercial customers

To calculate the number of customers added each year, the annual change in households for each county in the Company's service territory is determined using the Idaho Economics Summer 2018 Economic Forecast for the State of Idaho by John S. Church ('18 Forecast), dated October 2018 (see Exhibit 2, Section A). Using the assumption that a new household means a new dwelling is needed, the annual change in households by county is multiplied by Intermountain's market penetration rate in that region to determine the additional residential new construction customers. Next, that number is multiplied by the IGC conversion rate, which is the anticipated percentage of conversion customers relative to new construction customers in those locales. This results in the number of expected residential conversion customers, which when added to the residential new construction numbers, equals the total expected additional residential customers by county.

To accurately estimate growth for the State Street AOI, which contains a small portion of Canyon County and a large portion of Ada County, an additional estimate is utilized. The Community Planning Association of Southwest Idaho (COMPASS) conducts annual forecasts based on defined 'Traffic Analysis Zones' (TAZ) within Ada County. According to COMPASS, the TAZ that coincides with the State Street AOI boundary is expected to grow 3.14% per year over the next 5 years. This annual growth rate is applied to the current customer count within that boundary to derive the estimated growth of the State Street AOI over the same time period.

The Central Ada AOI sits entirely in Ada County. Using the same methodology as described above, the Central Ada AOI growth was calculated to be 2.9% per year.

The residential new construction numbers by county are multiplied by the IGC commercial rate, which is the anticipated percentage of commercial customers relative to residential new construction customers in those locales, to arrive at the number of expected additional commercial customers.

With the continued resurgence in the housing market, Intermountain growth projections are up considerably, when compared to the 2017 IRP. The '18 Forecast household numbers are employed to determine the relative overall number of customer additions, as well as the distribution of those customer additions across the Company's service territory.

The following graph depicts the relationship, or shape, of customer additions by AOI:

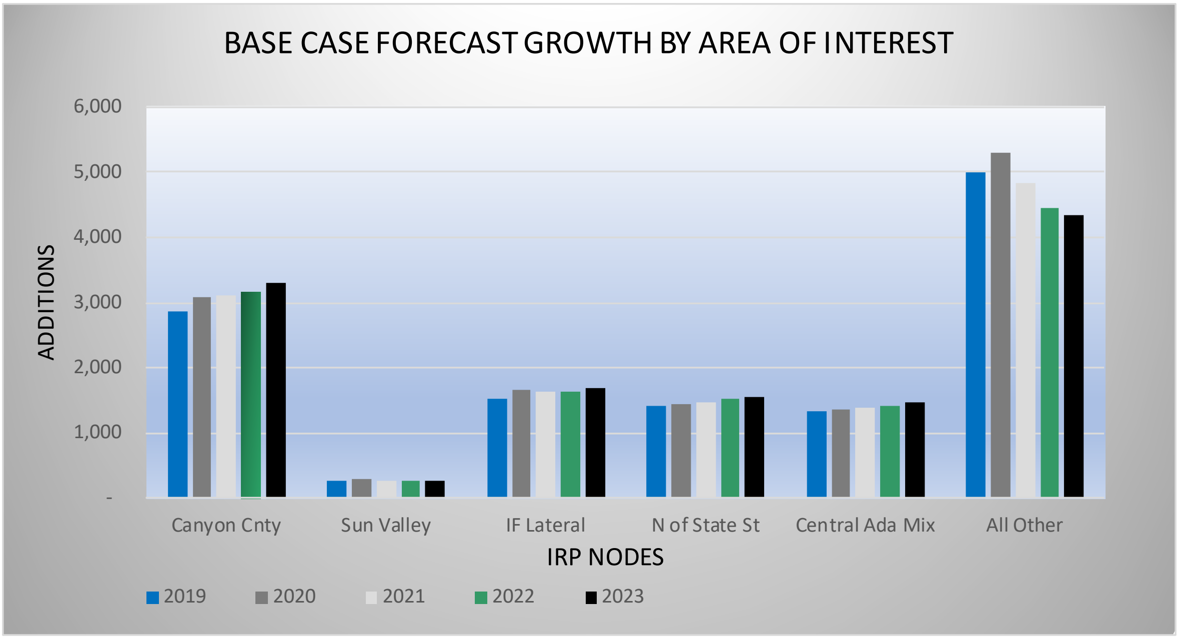


Figure 2: Base Case Forecast Growth by Area of Interest

The '18 Forecast contains three economic scenarios: base case, low growth, and high growth. IGC has incorporated these scenarios into the customer growth model and has developed three five-year core market customer growth forecasts. The following graph shows the annual additional customers forecast for each of the three economic scenarios.

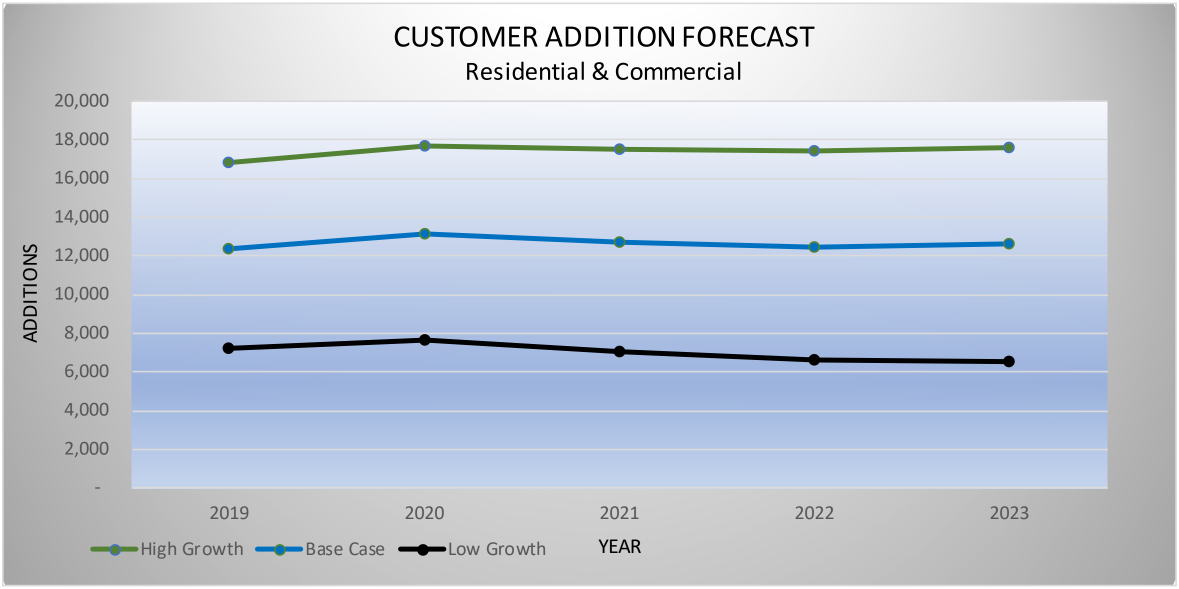


Figure 3: Customer Addition Forecast – Residential & Commercial

The following graph shows the difference in base case annual additional customers between the 2017 and 2019 IRP forecast years common to both studies:

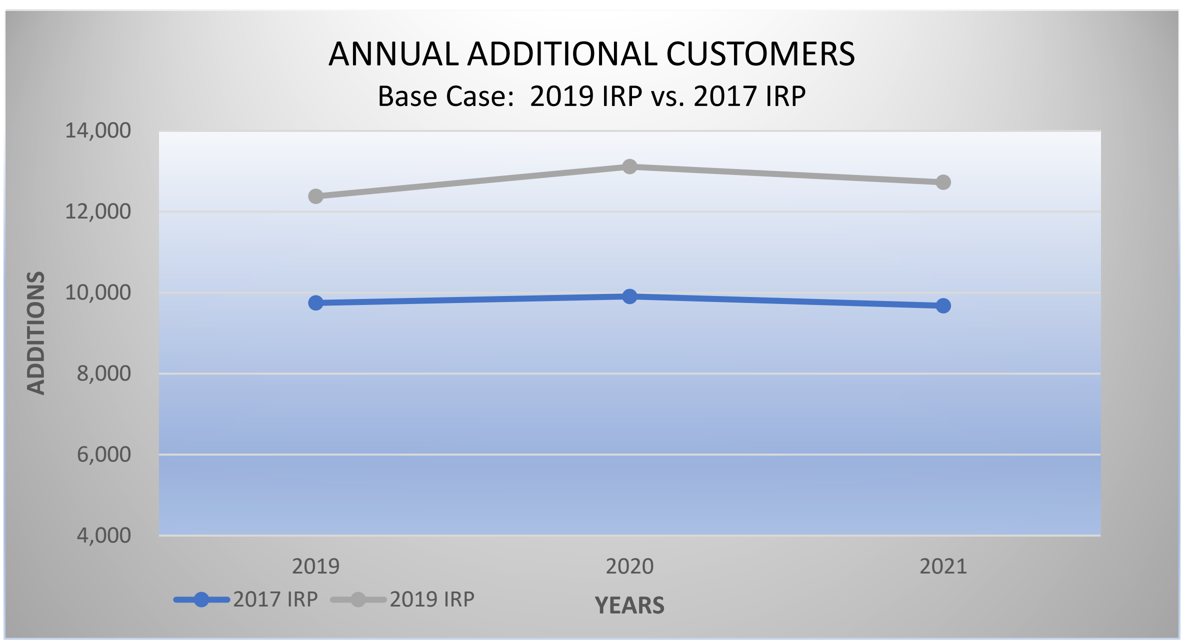


Figure 4: Annual Additional Customers – Base Case: 2019 IRP vs. 2017 IRP

As indicated, the economic recovery and its resulting positive impact on housing and business growth has resulted in a much increased IGC customer growth forecast in the years common to the 2017 and 2019 IRP's.

The following tables show the results from the five-year customer growth model for each scenario for the annual additional or incremental customers and total customers at each year-end.

Table 1: Forecast New Customers

Forecast New Customers					
	2019	2020	2021	2022	2023
LOW GROWTH	7,197	7,655	7,072	6,605	6,528
BASE CASE	12,384	13,115	12,733	12,490	12,642
HIGH GROWTH	16,792	17,722	17,492	17,412	17,610

Table 2: Forecast Total Customers

Forecast Total Customers					
	2019	2020	2021	2022	2023
LOW GROWTH	371,582	379,237	386,309	392,914	399,442
BASE CASE	376,769	389,883	402,616	415,106	427,748
HIGH GROWTH	381,177	398,899	416,391	433,803	451,412

The following sections explore, more fully, the different components of the customer forecast, including the ‘18 Forecast, market penetration and conversion rates, and commercial customer growth.

Household Projections

The ’18 Forecast provides county by county projections of output, employment and wage data for 21 industry categories for the state of Idaho, as well as population and household forecasts. This simultaneous equation model uses personal income and employment by industry as the main economic drivers of the forecast. The model also utilizes forecasts of national inputs and demand for those sectors of the Idaho economy having a national or international exposure. Industries that do not have as large of a national profile and are thus serving local communities and demand are considered secondary industries. Local economic factors, rather than the national economy determine demand for these products.

The ’18 Forecast uses two methods for population projections: (1) a cohort-component population model in which annual births and deaths are forecast, the net of which is either added to or subtracted from the population; and (2) an econometric model which forecasts population as a function of economic activity. The two forecasts are then compared and reconciled for each quarter of the forecast. Migration into or out of the state is derived as a result of this reconciliation.

As previously mentioned, the ‘18 Forecast provides three scenarios: (1) base case, (2) high growth, and (3) low growth. The base case scenario assumes a normal amount of economic fluctuation, a normal business cycle. This becomes the standard against which changes in customer growth, as affected by the low and high growth scenarios can be measured.

The Base Case Economic Growth Scenario

In the base case scenario of the Summer 2018 Idaho Economic Forecast it is projected that Idaho will continue to be an attractive environment for population and household growth. In the decade of the 1990s Idaho's population increased at an annual average rate of 2.5 % per year. The 2008 national recession brought about a significant decline in Idaho's nonagricultural employment over the 2000 to 2010 period and a slowing of the rate of population growth in the state—slowing to an annual average rate of 1.9 % per year over the decade. Nevertheless, that rate of population growth was higher than Idaho's annual average rate of natural population growth (births minus deaths) of nearly 1.0 % per year indicating that Idaho continued to attract an in-migration of population even during that period of tough economic times.

Recent statistics indicate that Idaho’s economy and population growth have again regained momentum. In 2016, Idaho was ranked as the third fastest growing state in the nation with an annual increase of 1.83%. In 2017, Idaho’s population growth accelerated to an annual gain of 2.2% and was ranked as the fastest growing state in the nation (an absolute gain of nearly 37,000 persons). The population growth has not been equally distributed across the state. Since the 2010 US Census through mid-year 2017, it is estimated that Idaho’s population has increased by nearly 149,400. Nearly 62.5% of those population gains were posted in the Treasure Valley with Ada and Canyon counties accounting for 93,200 of the state’s population growth. The counties along the Idaho Falls Lateral in eastern Idaho have posted a population gain of nearly 17,800 since the 2010 Census; 11.9% of the overall population growth in the state. The Magic Valley counties posted a gain of 10,300 in population since the last census, and accounted for 6.9% of the state’s overall population growth.

It is projected that during the 25-year period 2015 to 2040 that Idaho's population will increase by 906,700 reaching a total population of 2,559,500 by the year 2040—an annual average pace of 1.8% per year. The number of households in the state is expected to increase at a slightly faster pace of 2.1% per year over the 2015 to 2040 period adding nearly 423,400 additional households statewide. Ada and Canyon counties are projected to capture the majority of the state’s future population and household growth over the 2015 to 2040 period—with a gain of 568,000 persons and 248,200 households. Ada county is projected to see an absolute population increase of 319,000 (150,400 households) over the 2015 to 2040 period.

Canyon county will take up second place statewide with a projected absolute population gain of 249,700 (a 97,900 increase in the number of households). In eastern Idaho, the Bonneville, Madison, Bannock, and Jefferson counties are expected to see increases in population of 54,800; 34,500; 26,300; and 17,900, respectively, over the 2015 to 2040 forecast period. A total growth in population and households of 140,400 persons and 61,600 households in the eight counties along the Idaho Falls Lateral is forecasted over the 25-year period.

In the base case scenario of the ‘18 Forecast, it is assumed that the state of Idaho will continue to be an attractive environment for the in-migration of new business. In spite of the employment losses that the state experienced in the 2008 economic downturn, Idaho's industries have regained economic traction and have continued their expansion within the state. Another dynamic that has been examined by the Federal Reserve Bank of San Francisco is an exodus of population and some businesses from the state of California. While California’s population numbers continue to increase, the annual average rate of population growth in California is less than the state’s natural rate of population growth (births minus deaths). This fact indicates that California is experiencing an annual net out-migration between 0.2% and 0.3% of its population. Given California’s current population of greater than 39,000,000, an annual out-migration of 0.2% to 0.3% translates to 80,000 to 120,000 persons relocating each year. Driver’s license surrender statistics from the Idaho Department of Transportation indicate that Idaho is capturing a significant portion of relocating Californians. For many of the businesses relocating from California, a primary reason behind their exodus is the relatively high cost of doing business and the burden of business regulation in California. This forecast views this circumstance as an ongoing phenomenon that is not likely to abate in the near-term and will be a significant factor contributing to economic and population growth in the western states in proximity to California.

Total non-agricultural employment in Idaho is projected to increase by 336,200 (an annual average increase of 1.7% per year) over the 2015 to 2040 period. Again, Ada and Canyon counties are projected to capture the majority of those non-agricultural employment gains with a projected increase of 199,400 non-agricultural jobs, an annual average increase of 2.2% per year. During those 25 years, Ada and Canyon counties are projected to account for 59.2% of the total non-agricultural employment gains statewide.

The counties along the Idaho Falls Lateral (Bannock, Bingham, Bonneville, Butte, Fremont, Jefferson, Madison, and Power) are projected to see an absolute increase in non-agricultural employment of nearly 58,000, an annual average rate of 1.15% per year. In south central Idaho, (Blaine, Camas, Cassia, Gooding, Jerome, Lincoln, Minidoka, and Twin Falls counties) total non-agricultural employment is projected to increase by nearly 27,800 jobs, an annual average pace of 1.1% per year, over the forecast period.

Similar to the economic outlook in the 2017 IRP, Idaho's manufacturing sector will not be the driver of economic growth in the state. Over the 10-year period 2000 to 2010 manufacturing employment in the state decreased by 17,200 jobs. In the five years since 2010 Idaho regained nearly 8,500 of those lost manufacturing jobs.

In the longer term, manufacturing employment in the state is projected to only increase by a modest 5,600 jobs over the 2015 to 2040 period—an annual average gain of 0.8% per year. In Ada and Canyon counties manufacturing employment is projected to increase by nearly 4,800 over the forecast period.

During the historical period, 1990 to 2010, food processing employment in Ada and Canyon counties had been increasing—largely on the strength of job gains in the dairy products manufacturing sector. In the current forecast period, it is expected that the dairy products manufacturing firms will continue to post job gains. At the same time, it is projected that the vegetable processing firms in Ada and Canyon counties will continue to experience further job losses over the forecast period. The total effect of these trends in the food processing industry is that the Company does not project the food processing sector to be a significant contributor to any gains in manufacturing employment in Ada and Canyon counties. However, in south central Idaho, the food processing sector is projected to be the driving factor behind forecasted manufacturing employment gains of nearly 1,100 jobs in the Twin Falls area over the forecast period.

Employment in Idaho's lumber and wood products manufacturing sector slipped in the last recession. Future job gains in the lumber and wood products manufacturing sector is projected to be minimal over the forecast period. Statewide employment in stone, clay, and glass products and fabricated metal products manufacturing is expected to increase in proportion to population and household growth in the state. Idaho's electronics and machinery manufacturing sectors are not expected to regain the jobs lost during the last recession. No new machinery or electronics manufacturing facilities are anticipated to be located in Idaho during the forecast period.

Statewide employment in the transportation, trade, and utilities industries is projected to increase by nearly 28,700 jobs over the forecast period—an annual average increase of 1.0% per year. In general, employment in the transportation, trade, and utilities industries is projected to increase at a pace that is half of the rate of population and household growth statewide. In Ada and Canyon counties, employment in the transportation, trade, and utilities industries is projected to increase by 22,400 over the forecast period—representing 78% of the projected statewide employment gains in the sector. Counties along the Idaho Falls Lateral are projected to see transportation, trade, and utilities jobs increase by 4,300 over the 25-year period—representing 15% of the sector's projected job gains statewide.

Over the forecast period, employment in Idaho's service industries are projected to be the area of the greatest future employment growth in the state. Professional and business services employment statewide is projected to increase by 73,400 over the forecast period—an annual average increase of 2.6% per year. Employment in education and health services is projected to add 75,000 jobs statewide during the forecast period while the leisure and hospitality services sector is projected to add nearly 31,700 jobs. Ada and Canyon County employment in the professional and business services sector is projected to increase by 45,600, representing 62.1% of the projected gains statewide. Similarly, projected employment gains in Ada and Canyon counties in the educational and health services sector, and the leisure and hospitality services sector are projected to add nearly 46,000 jobs (61.3% of the total statewide gain), and 21,800 jobs (68.8% of the projected total statewide gain), respectively, over the forecast period.

Even with the tight fiscal conditions that came with the 2008 national recession, employment in Idaho's government sector increased by nearly 9,800 during the 2000 to 2010 period. Between 2010 and 2015, government employment in the state slowed adding only about 2,000 jobs in the five-year period. However, it is projected that government employment in Idaho will regain some momentum and increase by nearly 18,200 over the 2020 to 2030 period. In the long term, the forecast projects that government employment statewide will increase by 50,800 over the forecast period—an annual average increase of 1.3% per year. Generally, the bulk of the increase on government employment will be in the state and local government area and largely associated with the need for additional local government employees to provide basic services to a forecasted ever-growing population in the state. It is projected that government employment gains of 26,900 over the forecast period in Ada and Canyon counties will represent nearly 53.0% of the projected government job gains statewide.

The High and Low Economic Growth Scenarios

The high growth and low growth scenarios of the '18 Forecast present alternative views of the economic future of Idaho and its 44 counties. The high growth scenario of the '18 Forecast presents a vision of a more rapidly growing economy in Idaho. For example, the high growth scenario produces a projected statewide population of 2,060,323 in the year 2023 versus a base case scenario Idaho population forecast of 1,928,784 in the same year. The high growth scenario average annual compound rate of population growth from 2010 to 2040 is 2.0% per year.

Alternatively, the low growth Scenario of the '18 Forecast presents a slower economic outlook for the Idaho economy. In the low growth scenario, Idaho's 2023 population is projected to reach the much lower level of 1,736,355, exhibiting an annual average compound growth rate of 1.2% per year from 2010 to 2040.

An examination of the possible economic and demographic events that could produce the economic and population growth projected in the high and low growth scenarios are outlined below:

The High Growth Economic Scenario

By the year 2040 the high growth scenario forecasts that population and households in Idaho is projected to be nearly 11.1% higher than the forecasted amounts in the base case scenario. This represents a projected population in the high growth scenario that is nearly 283,900 higher in the state by the year 2040 with an additional 114,100 households over the base case scenario. The projected gap between the high growth and base case scenarios widens in the years 2020-2030 as the Idaho economy regains some of the economic momentum that it established in the years 1990 through 2005. In the high growth forecast it is expected that stronger employment gains statewide will be a magnet for a stronger rate of population in-migration to the state.

In the high growth scenario of the '18 Forecast, Idaho is projected to be a modestly more attractive environment for manufacturing firms. Therefore, in spite of the employment losses that the state experienced in the 2008 recession, Idaho's manufacturing industries are projected to gain employment at a faster rate in the 2015 to 2025 period. In 2025, Idaho's manufacturing employment is expected to reach 72,200—2,800 jobs higher than the amount projected in the base case forecast. Over the longer term, manufacturing employment in the high growth forecast is projected to exceed the base case scenario by 4.1%, or 2,700 jobs, in the year 2040.

In the high growth forecast, it is assumed the food processing industry does not shed as many jobs at vegetable processing facilities across the state, and Idaho will continue to attract new food processing companies to the state. There are no expectations for the location of a new electronics manufacturing plant in the state as was the case in the high growth forecasts of prior IRPs. It is expected that employment in lumber and wood products manufacturing will continue to remain weak and not be a significant factor for future employment growth. However, the state may pick up some additional manufacturing jobs in machinery and equipment and fabricated metals manufacturing in the high growth scenario. Nevertheless, the prospects for additional employment in these manufacturing sectors will only offset natural productivity gains, and subsequent job attrition in the manufacturing sector. Transportation equipment manufacturing in the state is not expected to benefit from the stronger economic growth forecasted in the high growth scenario.

The Low Growth Economic Scenario

By the year 2040, the low growth forecast of population and households in Idaho is 12.5% lower than the forecasted amounts in the base case scenario. This represents a projected difference of nearly 318,700 fewer people in the state by the year 2040 and nearly 138,800 fewer households. In the low growth scenario, overall employment gains are projected to slow statewide, causing Idaho to be less attractive to a job-seeking population which would otherwise migrate to Idaho.

Idaho's manufacturing employment in the low growth scenario is not forecasted to significantly recover from the 2008 national recession.

In the low growth scenario, the state's loss of jobs in the food processing industry accelerates and nearly 1,500 additional jobs are lost over the forecast period. The potato processing plants in southern Idaho would experience the bulk of these job losses. The low growth scenario assumes that the JR Simplot plant in Caldwell will shed over 1,000 jobs by the year 2020. Furthermore, the sugar processing plants in southern Idaho are projected to feel increased pressure from competition and will find it necessary to close one of the sugar processing plants in either Nampa, Paul, or Twin Falls. The dairy industry and its associated food processing plants are projected to reach a point where no further capacity can be added due to increased population and environmental pressures.

Employment losses in Idaho's lumber and wood products manufacturing industry are projected to accelerate in the low growth scenario. In this scenario, the brunt of these additional losses will be felt in those portions of the wood products industry that are increasingly vulnerable to low-cost foreign produced products (i.e. the woodgrain molding plants in Fruitland and Nampa).

Idaho's electronics and machinery manufacturing industries are expected to experience further job losses in the low growth forecast. Additionally, employment in stone, clay, and glass products and fabricated metal products manufacturing are both projected to be at lower levels of total employment than in the base case scenario.

In general, in the low growth scenario, manufacturing industry employment in the year 2040 is projected to be nearly 6,400 jobs (9.4%) lower than in the base case scenario.

Transportation, trade, and utilities employment in the low growth scenario is projected to have nearly 3,200 fewer jobs (2.0% lower) by the year 2040 than in the base case scenario. Lower overall economic growth projected in the low growth scenario produces lower levels of demand for transportation services and fewer buying opportunities of additional retail stores. Additionally, the low growth scenario projects that there will be closures or downsizing of some of the state's food processing facilities, which all require significant amounts of truck transportation.

The low growth forecast of statewide employment in the finance, insurance, and real estate sector is about 5,700 (14.0%) lower than in the base case scenario by the year 2040. Again, the difference is largely due to the lower levels of population and household growth projected in the low growth scenario.

The outlook for service industry employment in the low growth scenario assumes that employment growth in the service sector will slow, proportionate to the projected slower growth in population and households statewide. Further, Idaho is projected to be less attractive to those service industry firms from outside of Idaho that may have considered relocating all or a portion of their activities to Idaho. Furthermore, the low growth scenario forecasts that Idaho's competitive position for attracting new business will be degraded and that the nearby states of Utah, Oregon, and Nevada will capture a larger proportion of firms making relocation and expansion decisions.

Future government employment in the low growth scenario is projected to be 8.6% (14,800 jobs) lower than the base case scenario by the year 2040. As previously mentioned for other industries, the reason for projected lower levels of government employment in the low growth scenario are the slower rates of population and household growth in the low growth forecast. The low growth scenario projects that the number of assigned military personnel at Mountain Home Airforce Base will remain at levels that are similar to those at the present time.

Forecast Households

As previously stated, the basis for the customer growth forecast relies on the annual variance, or change, in households from year to year, within the counties in which IGC operates. The forecast number of total households; low growth, base case and high growth scenarios, is shown in Table 3.

Table 3: Forecast Total Households – IGC Service Area

Forecast Total Households IGC Service Area					
	2019	**2020**	**2021**	**2022**	**2023**
LOW GROWTH	469,505	477,147	484,232	490,876	497,464
BASE CASE	500,551	513,550	526,193	538,618	551,216
HIGH GROWTH	520,267	537,748	555,041	572,276	589,740

The variance between the common years in the 2017 and 2019 IRPs for forecast total households is depicted in the graph below.

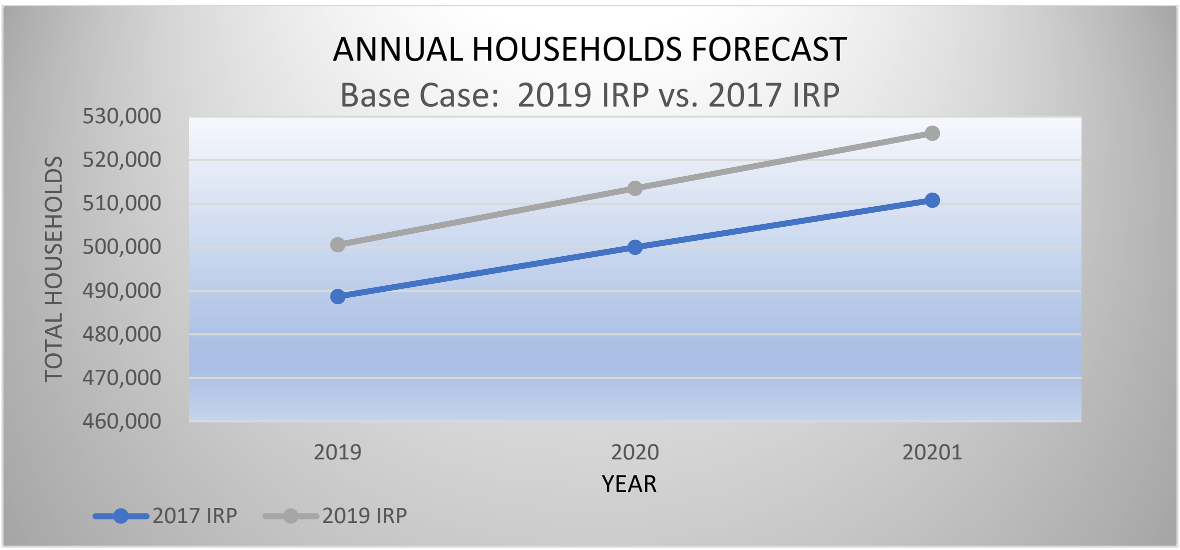


Figure 5: Annual Households Forecast – Base Case: 2019 IRP vs. 2017 IRP

The graph below provides a visual depiction of the variance in household growth for high growth, base case and low growth scenarios for the 23 counties which Intermountain Gas Company serves.

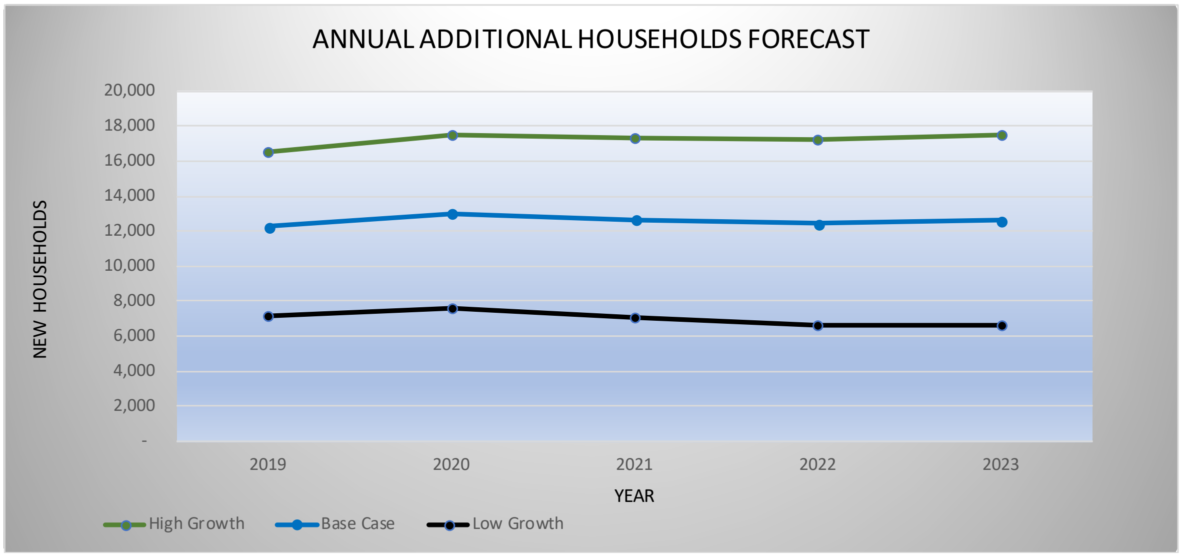


Figure 6: Annual Additional Households Forecast

A comparison of the base case household growth, between the common years in the 2017 and 2019 IRPs, is depicted below.

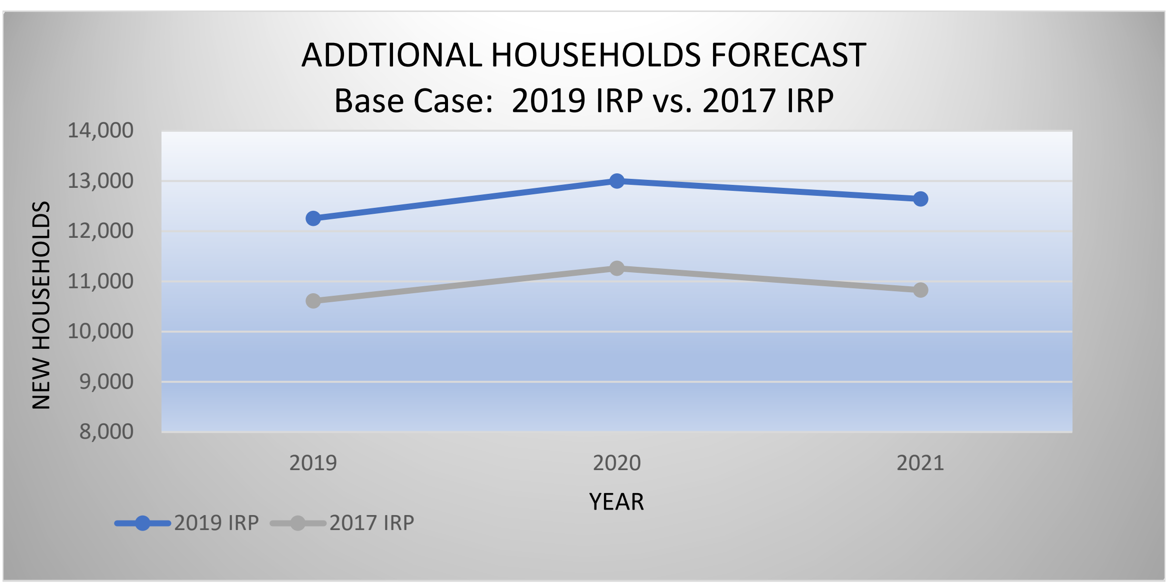


Figure 7: Additional Households Forecast – Base Case: 2019 IRP vs. 2017 IRP

Market Share Rates

IGC utilizes market penetration rates that vary across its service territory. These regional penetration rates are applied to the counties within the Company's service territory within three specific regions: East, Central, and West. These penetration rates are the ratio of IGC's additional residential new construction customers to the total building permits in those regions. The penetration rate is then applied to the forecasted additional households to derive the estimated residential new construction customers by region.

IGC develops market penetration rates by way of the county construction reports which IGC Energy Services personnel use in prospecting for new construction customers. To derive the market penetration rate, the residential new construction customers in the specific areas covered by these reports are divided by the total dwelling permits listed in these reports. In addition, the tracking process includes whether the new home is within reach of existing mainline; i.e., the home can be readily served within IGC's main and service policy without financial contribution by the customer for the extension of service. The areas covered are the jurisdictions/counties within each operation district within the Company's service area which publish monthly building permits. More generally described/identified as: Nampa, Boise, Twin Falls, Pocatello, and Idaho Falls. This data is collected and tracked monthly, by jurisdiction. The cumulative annual penetration rate, by district, is then applied to the household growth forecast per district, to derive the forecast for new construction growth.

The penetration rates used, based on the methodology described above, are depicted in the chart below. Variations in penetration rates across the Company's service area is a function of the variation in population density across the 23 counties which IGC serves in relation to the service area within those counties.

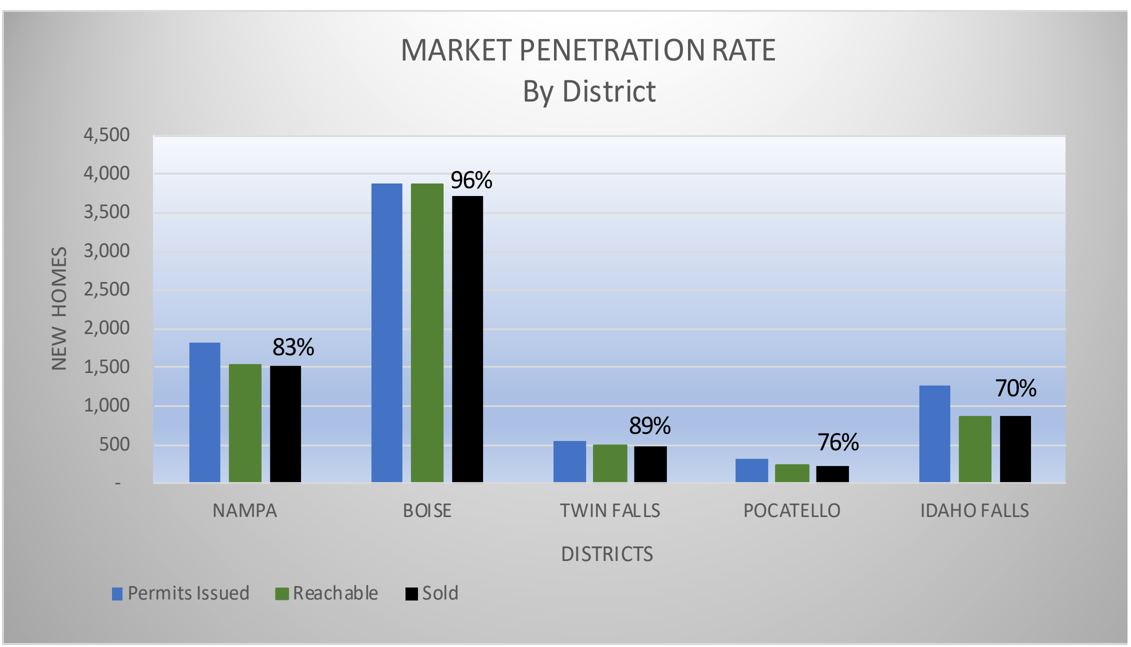


Figure 8: Market Penetration Rate – By District

The following graph illustrates the relationship between the three economic scenarios for the annual residential new construction growth forecast for 2019 – 2023:

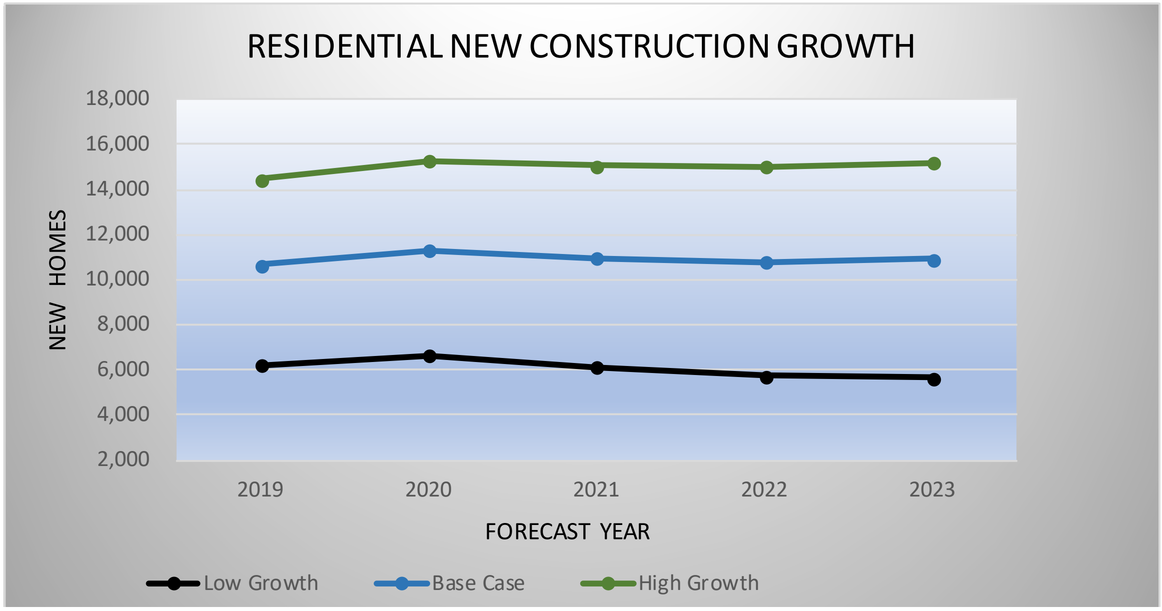


Figure 9: Residential New Construction Growth

The following graph shows the difference in base case residential new construction customer growth between the 2017 and 2019 IRP forecast years common to both studies:

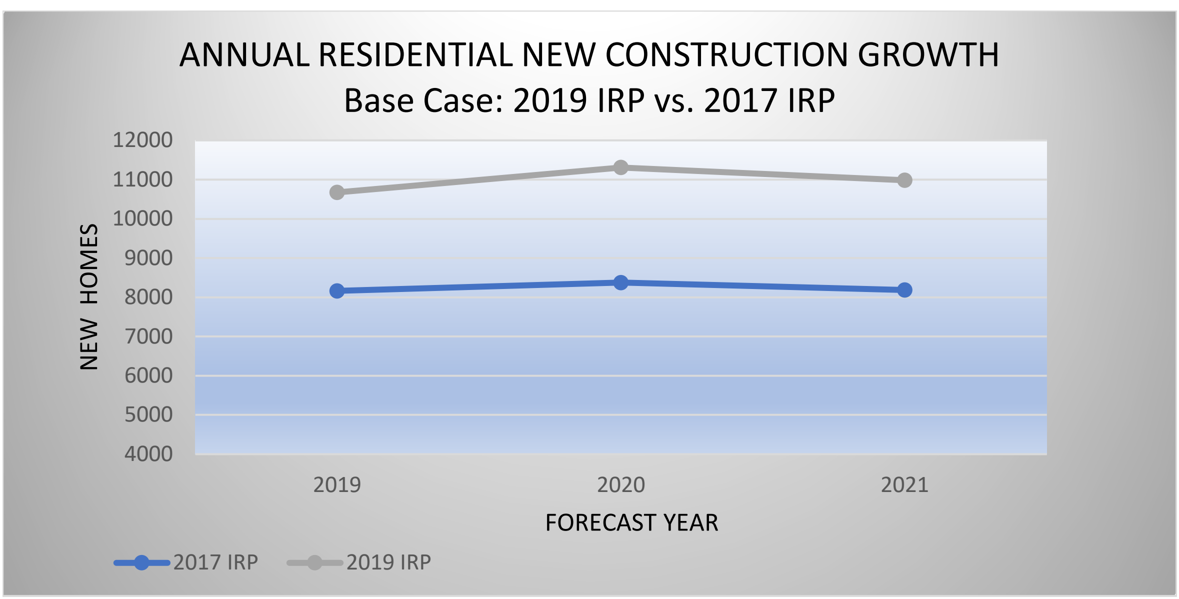


Figure 10: Annual Residential New Construction Growth – Base Case: 2019 IRP vs. 2017 IRP

Conversion Rates

The conversion market represents another source of customer growth for the Company. IGC acquires these customers when homeowners replace an electric, oil, coal, wood, or other alternate fuel source furnace/water heater with a natural gas unit. IGC forecasts these customer additions by applying regional conversion rates based on historical data and future expectations. The following table shows, by region, the assumed conversion rates used in the IRP. These rates represent the percentage of new customer additions which will be conversions. The calculated conversion forecast is then added to the new construction forecast to derive the total residential growth forecast.

The table below illustrates the conversion rates used in the 2019 and 2017 IRPs.

Table 4: Regional Conversion Rate

Regional Conversion Rate		
	2019	**2017**
EASTERN REGION	7%	9%
CENTRAL DIVISION	20%	21%
WESTERN REGION	19%	23%

The following graph illustrates the relationship between the three economic scenarios for the annual residential conversion growth forecast for 2019 – 2023:

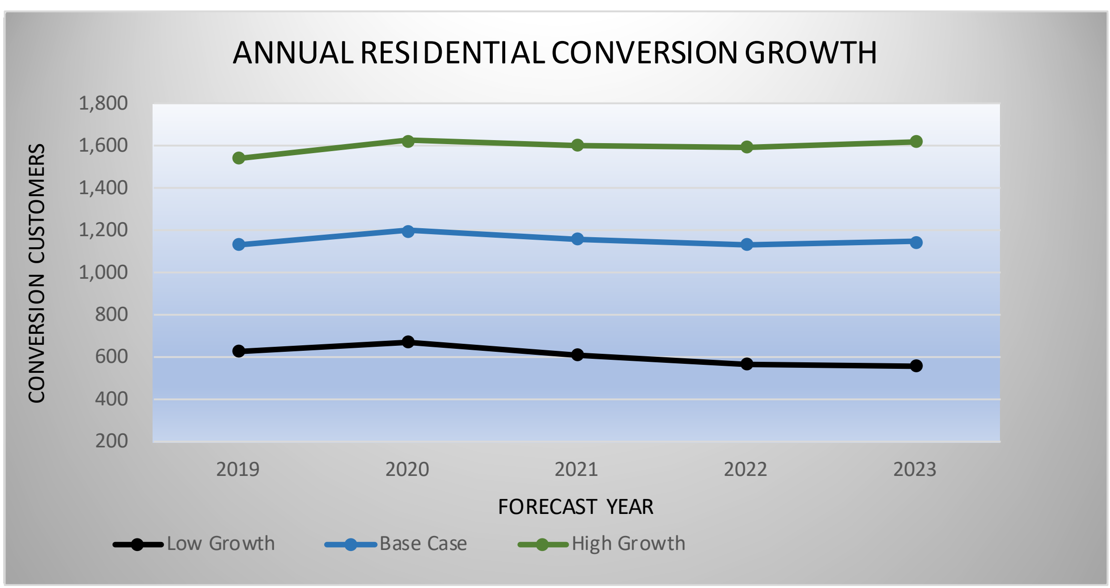


Figure 11: Annual Residential Conversion Growth

The following graph shows the difference in the base case forecast of residential conversion customer growth between the 2017 and 2019 IRP forecast years common to both studies:

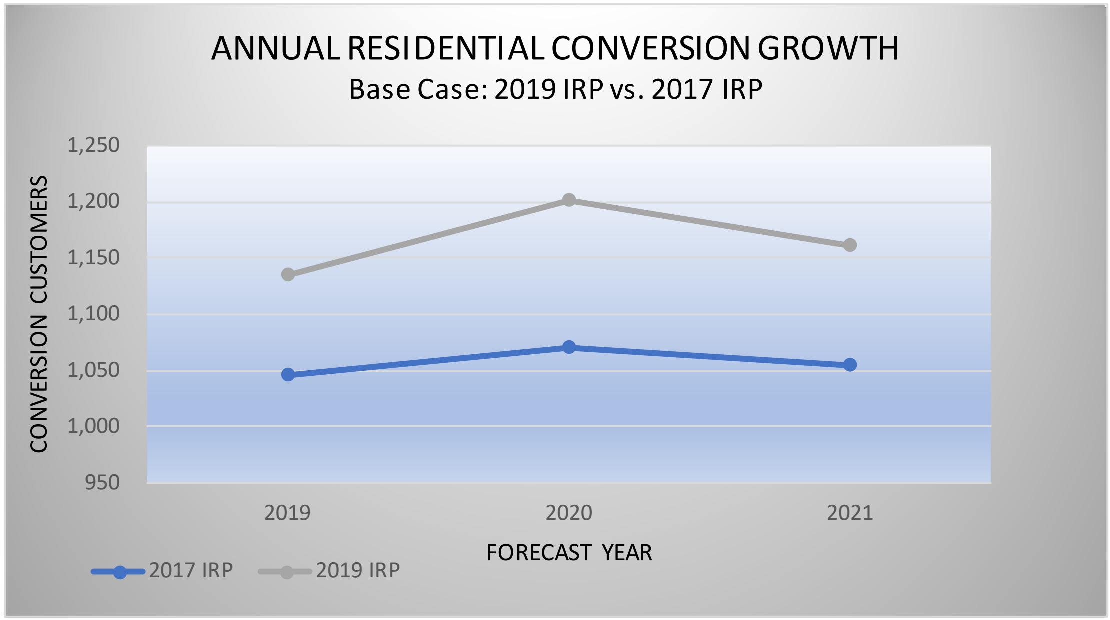


Figure 12: Annual Residential Conversion Growth – Base Case: 2019 IRP vs. 2017 IRP

Commercial Customer Forecast

Commercial customer growth is forecast as a certain proportion of new construction customer additions based on the idea that new households require additional new businesses to serve them. Based on the most recent three-year sales data, the ratio of commercial customer growth to residential growth for the west, central, and east regions was 4.80%, 8.12%, and 5.83%, respectively. Therefore, regional ratios of 5% for the west, and 8% for central, and 6% for the east are used in the base case, high growth, and low growth scenarios. The table below illustrates the variation in this variable from the previous IRP.

Table 5: Commercial Rate Factor

Commerical Rate Factor		
	2019	**2017**
EASTERN REGION	5.83%	11.21%
CENTRAL DIVISION	8.12%	10.36%
WESTERN REGION	4.80%	5.06%

The following graph shows the forecast annual additional commercial customers for the low growth, base case and high growth scenarios from the '18 Forecast.

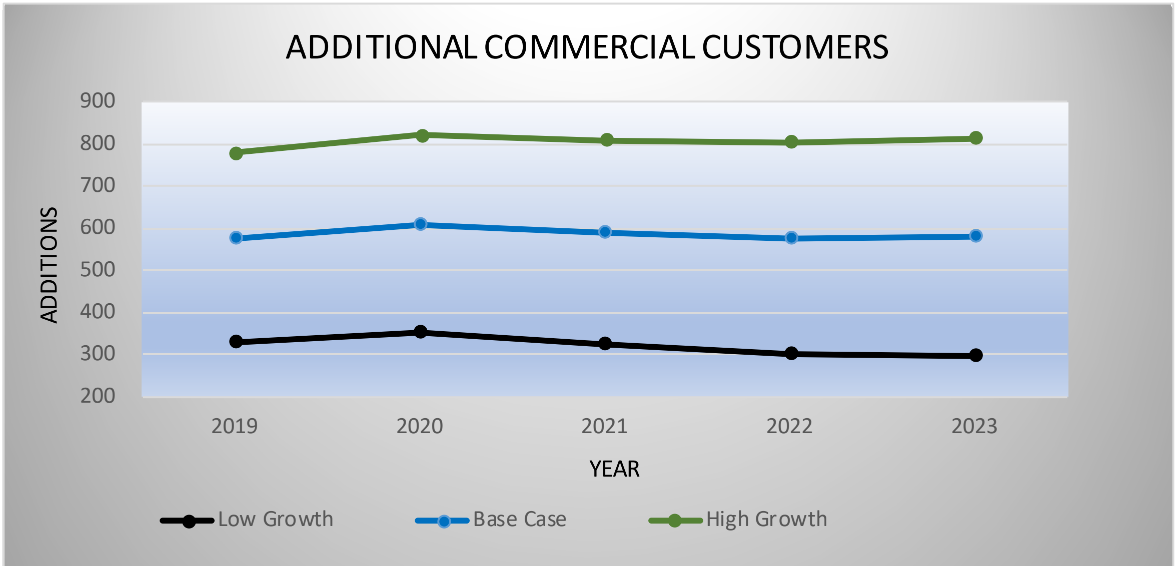


Figure 13: Additional Commercial Customers

The following graph shows the difference in base case commercial customer growth between the 2017 and 2019 IRP forecast years common to both studies:

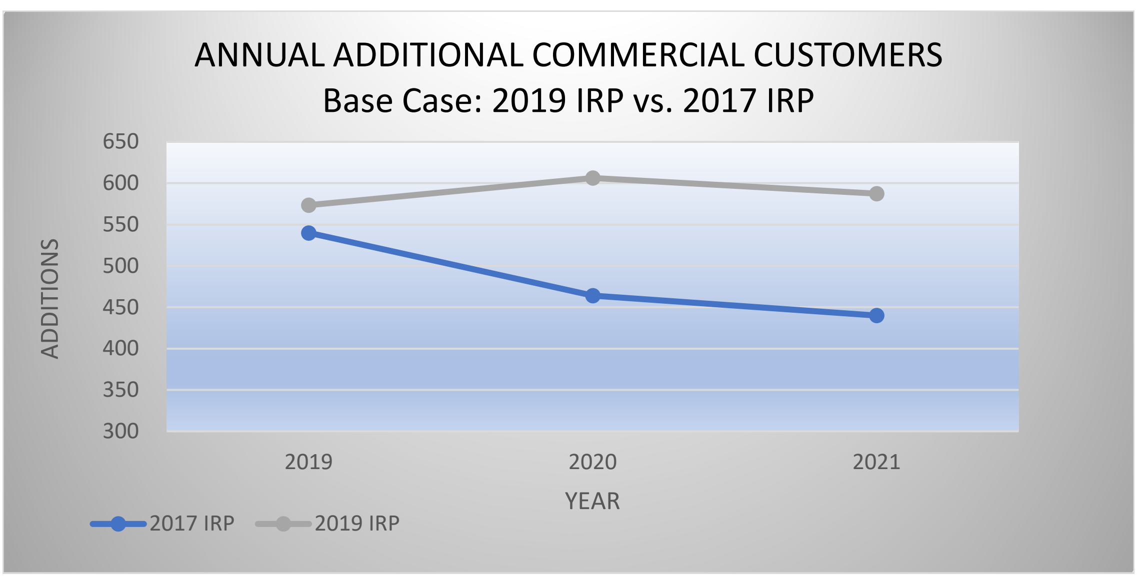


Figure 14: Annual Additional Commercial Customers – Base Case: 2019 IRP vs. 2017 IRP

Heating Degree Days & Design Weather

Intermountain's demand forecast captures the influence weather has on system loads by using Heating Degree Days (HDDs) as an input. HDDs are a measure of the coldness of the weather based on the extent to which the daily mean temperature falls below a reference temperature base. HDD values are inversely related to temperature which means that as temperatures decline, HDDs increase. The standard HDD base, and the one Intermountain utilizes in its IRP, is 65°F (also called HDD65). As an example, if one assumes a day where the mean outdoor temperature is 30°F, the resulting HDD65 would be 35 (i.e. 65°F base minus the 30°F mean temperature = 35 Heating Degree Days). Two distinct groups of heating degree days are used in the development of the IRP: Normal Degree Days and Design Degree Days.

Since Intermountain's service territory is composed of a diverse geographic area with differing weather patterns and elevations, Intermountain uses weather data from seven NOAA weather stations located throughout the communities it serves. This weather data is weighted by the customers in each of the geographic weather districts to arrive at weighted weather for the entire company. Several AOIs are also addressed specifically by this IRP. Those segments are assigned unique degree days as discussed in further detail below.

Normal Degree Days

A Normal Degree Day is calculated based on historical data, and represents the weather that could reasonably be expected to occur on a given day. The Normal Degree Day that Intermountain utilizes in the IRP is computed based on weather data for the 30 years ended December 2018. The HDD65 for January 1st for each year of the 30-year period is averaged to come up with the average HDD65 for the thirty year period for January 1st. This method is used for each day of the year to arrive at a year's worth of Normal Degree Days.

Design Degree Days

Design Degree Days are an estimation of the coldest temperatures that can be expected to occur for a given day. Design Degree Days are useful in estimating the highest level of customer demand that may occur, particularly during extreme cold or "peak" weather events. For IRP load forecasting purposes, Intermountain makes use of design weather assumptions.

Intermountain's design year is based on the premise that the coldest weather experienced for any month, season or year could occur again. The basis of a design year was determined by evaluating the weather extremes over the period of record from NOAA. That review revealed Intermountain's coldest 12 consecutive months to be the 1984/1985 heating season (October 1984 through September 1985). That year, with certain modifications discussed below, represents the base year for design weather. These degree days reflect a set of temperature extremes that have actually occurred in Intermountain's service area. These extreme temperatures would result in a maximum customer usage response due to the high correlation between weather and customer usage.

Peak Heating Degree Day Calculation

Intermountain also engaged the services of Dr. Russell Qualls, Idaho State Climatologist, to perform a review of the methodology used to calculate design weather, and to provide suggestions to enhance the design weather planning. One crucial area that Dr. Qualls was able to assist Intermountain in was developing a method to calculate a peak day, as well as in designing the days surrounding the peak day.

To develop the peak heating degree day, or coldest day of the design year, Dr. Qualls fitted probability distributions to as much of the entire period of record from seven weather station locations (Caldwell, Boise, Hailey, Twin Falls, Pocatello, Idaho Falls and Rexburg) as was deemed reliable. From these distributions he calculated monthly and annual minimum daily average temperatures for each weather location, corresponding to different values of exceedance probability. Two probability distributions were fitted, a Normal Distribution, and a Pearson Type III (P3) distribution. Dr. Qualls suggested it is more appropriate for Intermountain to use the P3 distribution as it is more conservative from a risk reduction standpoint.

According to Dr. Qualls, “selecting design temperatures from the values generated by these probability distributions is preferable over using the coldest observed daily average temperature, because exceedance probabilities corresponding to values obtained from the probability distributions are known. This enables IGC to choose a design temperature, from among a range of values, which corresponds to an exceedance probability that IGC considers appropriate for the intended use”.

Intermountain used Dr. Qualls’ exceedance probability data to review the data associated with both the 50 and 100 year probability events. After careful consideration of the data, Intermountain determined that the company-wide 50 year probability event, which was a 79 degree day, would be appropriate to use for our design weather model. For modeling purposes, this 79 degree day was assumed to occur on January 15th.

Base Year Design Weather

To create a design weather year from the base year, a few adjustments were made to the base design year. First, since the coldest month of the last 30 years was December 1985, the weather profile for December 1985 replaced the January 1985 data in the base design year. For planning purposes, the aforementioned peak day event was placed on January 15th.

To model the days surrounding the peak event, Dr. Qualls suggested calculating a five-day moving average of the temperatures for the past 30-year period to select the five coldest consecutive days from the period. December 1990 contained this cold data. The coldest day of the peak month (December 1985) was replaced with the 79 degree day peak day. Then, the day prior and three days following the peak day, were replaced with the four cold days surrounding the December 1990 peak day.

While taking a closer look at the heating degree days used for the LDCs, the Company noticed that the design weather HDDs in some months were lower than the normal weather HDDs. This occurred generally in the non-winter months, April through July. However, the Total Company and Idaho Falls Lateral design HDDs had this same occurrence in November, although the differences were minimal (1 to 3%). This occurred because, while the 1985 heating year was the coldest on record and therefore used as the base year for the design weather, the shoulder months were, in some cases, warmer than normal. Manipulating the shoulder and summer month design weather to make it colder would add degree days to the already coldest year on record, creating an unnecessary layer of added degree days. Intermountain decided not to adjust the summer and shoulder months of the design year.

After design modifications were completed, the total design HDD curve assumed a bell-shaped curve with a peak at mid-January (see Figure 15). This curve provides a robust projection of the extreme temperatures that can occur in Intermountain's service territory.

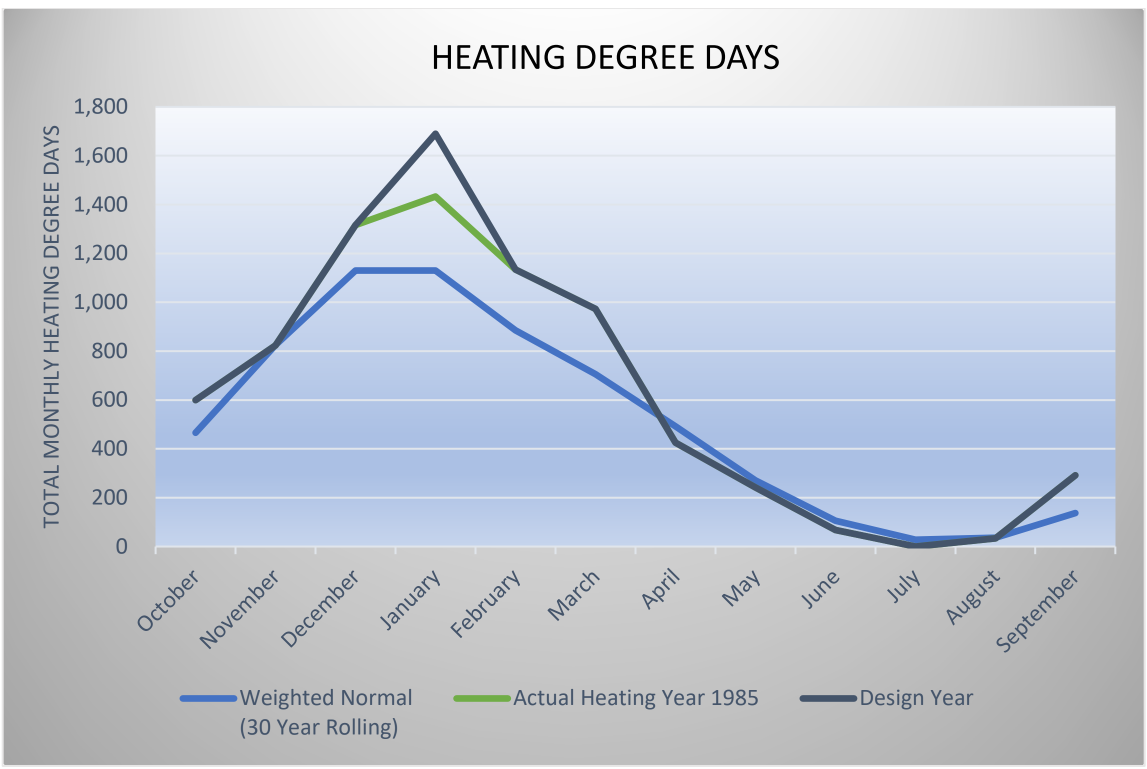


Figure 15: Heating Degree Days Graph

The resulting Normal, Base Year, and Design Year degree days by month are outlined in Table 6 displayed below:

Table 6: Heating Degree Days by Month

Monthly Heating Degree Days			
	Weighted Normal (30 Year Rolling)	Actual Heating Year 1985	Design Year
October	466	599	599
November	825	823	823
December	1,130	1,316	1,316
January	1,130	1,433	1,690
February	885	1,134	1,134
March	706	973	973
April	492	425	425
May	271	242	242
June	105	68	68
July	28	0	0
August	36	34	34
September	137	292	292
Total	6,211	7,339	7,596

Area Specific Degree Days

As noted earlier in this IRP, Intermountain has identified certain AOIs. These are areas Intermountain carefully manages to ensure adequate delivery capabilities either due to a unique geographic location, customer growth, or both.

The temperatures in these areas can be quite different from each other and from the Total Company. For example, the temperatures experienced in Idaho Falls or Sun Valley can be significantly different from those experienced in Boise or Pocatello. Intermountain continues to work on improving its capability to uniquely forecast loads for these distinct areas. A key driver to these area specific load forecasts is area specific heating degree days.

Intermountain has developed Normal and Design Degree Days for each of the areas of interest. The methods employed to calculate the Normal and Design Degree Days for each AOI mirrors the methods used to calculate Total Company Normal and Design Degree Days.

Usage Per Customer

The IRP planning process utilizes customer usage as an essential calculation to translate current and future customer counts into estimated demands on the distribution system and total demand for gas supply and interstate transportation planning. The calculated usage per customer is dependent upon weather and geographic location.

Methodology

Intermountain Gas utilizes a Customer Management Module (CMM) software product, provided by DNV GL as part of their Synergi Gas product line, to analyze natural gas usage data and to predict usage patterns on the individual customer level. DNV GL operates in over 100 countries and specializes in the maritime, oil, gas and energy industries. Its array of pipeline software has been a powerful engineering tool within the United States for decades, used by natural gas companies such as Avista, Pacific Gas and Electric, Dominion, Northwest Natural and Williams. The CMM product branch is used in correlation with Synergi Gas, a hydraulic modeling software program discussed in the Distribution System Modeling Section beginning on page 86 of this IRP.

The first step in operating the CMM is extensive data gathering from the Company's Customer Information System (CIS). The CIS houses historical monthly meter read data for each of Intermountain's customers, along with daily historical weather and the physical location of each customer. The weather data is associated with each customer based on location, and then related to each customer's monthly meter read according to the date range of usage.

After the correct weather information has been correlated to each meter read, a base load and weather dependent load are calculated for each customer through regression analysis over the historical usage period. DNV GL states that it uses a "standard least-squares-fit on ordered pairs of usage and degree day" regression. The result is a customer specific base load that is weather independent, and a heat load that is multiplied by a weather variable, to create a custom regression equation for each customer.

Should insufficient data exist to adequately predict a customer's usage factors, then CMM will perform factor substitution. Typically, the average usage of customers in the same geographical location and in the same customer rate class can be used to substitute load factor data for a customer which lacks sufficient information for independent analysis.

The first step prior to analyzing data through the CMM was to determine the appropriate time period to include in the study. A study by the American Gas Association found that average natural gas usage per customer is on the decline. The average U.S. home using natural gas uses 40% less today than it did four decades ago. Following the national efficiency trend, Intermountain has also noticed a decline in usage per customer in its service territory. Some possible reasons for the decline in usage per customer include the Idaho Residential Energy Code which is a code adopted in Idaho, and many other areas, beginning in 1991. This building standard was designed to improve the energy efficiency of new homes and commercial buildings. Around the same time, efficiency standards for furnaces and water heaters improved.

Additionally, programmable thermostats are now routinely installed in new construction, and many are installed in older homes as a way to reduce energy expense.

All of these conservation influences began impacting usage per customer in the 1990's. Because approximately 69% of Intermountain's customers are new since 1990, the efficiency factors and building codes have had a tremendous influence on our customer base. Additionally, rising energy prices in the early 2000's provided customers an economic incentive to improve the energy efficiency of their homes. Finally, as the Company's new Energy Efficiency Program continues to grow, there will be greater downward pressure on Intermountain's actual usage per customer. All of these are contributing factors to the structural changes shown in the data.

With all the structural shifts in historical data, and the significantly increased quantity of data utilized for regression, Intermountain has selected a four-year time series ending in May of 2018 to develop the usage per customer equations within this IRP. The selected time series is aligned with the recommended time study from DNV GL and contains homogenous data from a single CIS system.

Usage per Customer by Geographic Area

The Company recognizes that there could be significant differences in the way its customers use natural gas throughout its geographically and economically diverse service territory. Being sensitive to areas that may require capital improvements to keep pace with demand growth, Intermountain separated customers into distinct AOIs, and then determined specific usages per customer for each. The AOIs that Intermountain studied for possible usage per customer refinements included: Canyon County, Central Ada County, State Street Lateral, Sun Valley Lateral, and Idaho Falls Lateral.

In order to refine usage per customer to an AOI, customer addresses were used to create groups by town, and towns were combined with their related AOI. Central Ada and State Street AOI's share towns in their respective territories, so a combined geographic area was created to calculate their shared usage per customer. Towns on the Sun Valley Lateral were combined to calculate a single usage per customer, but for flow analysis purposes it was found that more granular customer breakdowns are required, and the usage per customer was represented separately for each town due to the range of usages and geographic sensitivity along the lateral. The same Sun Valley Lateral methodology was applied to the Idaho Falls Lateral.

Conclusion

The process described above is an effective methodology for calculating usage per customer. As discussed elsewhere in this IRP, the Company is in the process of implementing a fixed-network metering system. As the fixed-network system becomes fully deployed, the Company will be able to utilize the gathered data to further refine its usage per customer calculation.

As discussed in the Load Demand Curves Section of this IRP, the usage per customer data produced from the process described above is a critical component in the development of the

Company's load demand curves. The usage per customer data is applied to the customer forecast and design weather to create daily core market load projections for the IRP period.

Large Volume Customer Forecast

Introduction

The Large Volume (LV) customer group is comprised of approximately 125 of the largest customers on Intermountain's system from both an annual therm use and a peak day basis. Only customers that use at least 200,000 therms per year are eligible for Intermountain's LV tariffs. The LV tariffs provide two firm delivery services: a bundled sales tariff (LV-1) and a distribution system only transport tariff (T-4). The Company also offers an interruptible distribution system only transportation tariff (T-3).

The LV customers are made up of a mix of industrial and commercial loads and, on average, they account for over 50% of Intermountain's annual throughput and 24% of the projected 2020 design base case peak day. Nearly 98% of 2020 LV throughput reflects distribution system only transportation tariffs where customer-owned natural gas supplies are delivered to Intermountain's various citygate stations for ultimate redelivery via the company's distribution system to the customers' facilities.

Because the LV customers' volumes account for such a large portion of Intermountain's overall throughput, the method of forecasting these customers' overall usage is an important part of the IRP. These customers' growth and usage patterns differ significantly from the residential and commercial customer groups in two ways: first, the LV customers' gas usage pattern as a whole is not as weather sensitive as the core market customers which means that forecasting LV volumes using standard regression techniques based on projected weather does not provide statistically significant results. Secondly, the total LV customer count is so few that it falls below the number required to provide an adequate sample size.

Therefore, Intermountain has developed and utilizes an alternate, and very accurate method of forecasting based on historical usage, economic trends and direct input from LV customers. The graph on the next page compares the total Large Volume sales forecast from the 2017 IRP against actual therm sales for the years 2017 – 2019.

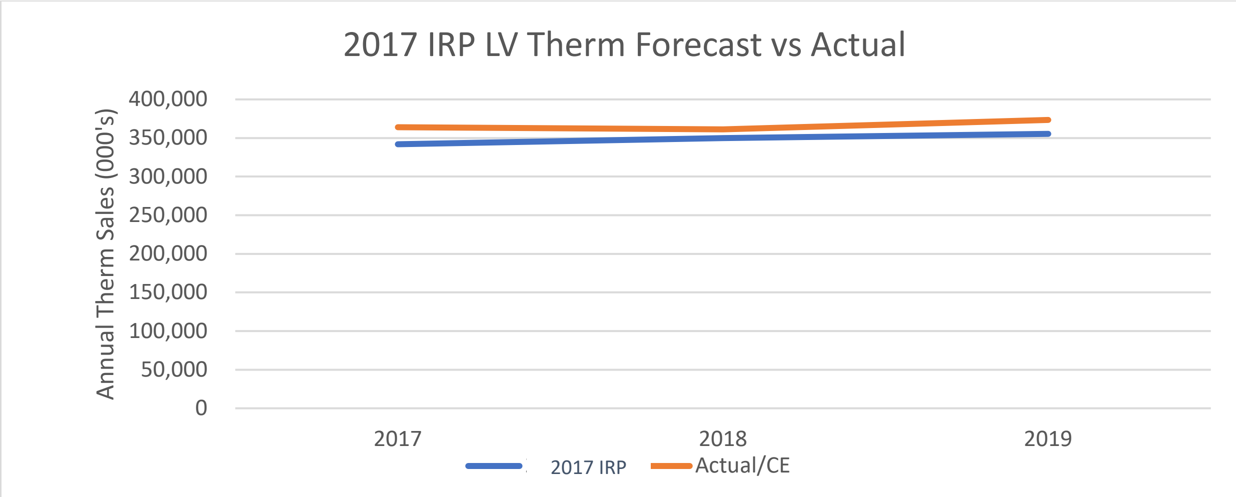


Figure 16: 2017 IRP Large Volume Therm Forecast vs Actual

Method of Forecasting

Intermountain maintains a historical therm usage database containing about 30 years of monthly therm usage data. The LV forecasting methodology begins by assessing each LV customer's monthly usage for the most recent three years. Then a representative 12-month period is selected as the base year. Typically, more weight is applied to the most recent 12-month period available unless known material variations would suggest a different base year.

An important source of forecasting information comes from the customers themselves. Prior to each IRP cycle, Intermountain sends out a survey to each customer requesting information relating to changes in usage patterns. Such a survey was sent out in July 2018. The survey form included a cover letter explaining the need for and the use of the requested information with the assurance that all responses would remain confidential (see Figure 17). The surveys provided each customer's historical peak day and monthly usage for the two years ending June 2018 (see Figure 18).

The historical information was provided to help the LV customer's management, engineers, and/or operations personnel identify how much and when recent natural gas usage patterns were likely to change going forward. Specifically, the survey requested projections of changes in natural gas consumption related to plant expansion, equipment modification or replacement and anticipated changes in product demand and production cycles through 2023.

Additionally, each customer was provided an opportunity to give recommendations for additional service options or other feedback. Nearly 40% of customers returned completed surveys and analysis of the returned surveys was completed by early September 2018. Where customers predicted material changes in future therm usage, the Company adjusted the annual 2019-23 base year data.

Forecast Scenarios

For the IRP, Intermountain prepared three separate LV monthly gas consumption forecasts (base case, high growth and low growth). The base case forecast started with the adjusted base year data as described above. That data was then combined with assumptions based on the most-expected economic trend to develop the five-year base case forecast. Other available data, including inquiries from the economic forecast provided by John Church (see Exhibit 2, Section A), other economic development organizations and alternate economic forecasts/assumptions were utilized to develop the high growth and low growth scenarios. For ease of analysis, the 125 existing and up to 14 projected new LV customers (per the high growth scenario) were combined into six homogeneous market segments:

2019 Existing LV Customers by Market Segment:

1) 17 potato processors
2) 38 other food processors including sugar, milk, beef, and seed companies
3) 3 chemical and fertilizer companies
4) 25 light manufacturing companies including electronics, paper, and asphalt companies
5) 34 schools, hospitals and other weather sensitive customers
6) 8 “other” companies including transportation-related businesses

Contract Demand

Every LV customer is required to sign a contract to receive service under any of the LV tariffs. An important element of the firm LV-1 sales and T-4 transportation contracts is the contract, or maximum daily firm quantity (MDFQ) which reflects the agreed upon maximum amount of daily gas and/or capacity the Company must be prepared to provide that firm LV customer on any given day including the projected system peak day that would occur during design weather.

T-3 customer contracts include a maximum daily quantity (MDQ) which represents the maximum amount of gas the Company’s service line and meter can flow. Because T-3 service is interruptible, Intermountain makes no assurances as to the amount of distribution capacity that will be available on any given day. For peak event modeling purposes, the IRP assumes T-3 customers are reduced to emergency plant-heat only. The IRP will use the term contract demand (CD) when referencing both MDFQ and MDQ. For this IRP, Intermountain utilized LV customer CD’s as they existed at June 1, 2018 for the beginning point of the base case.

While many LV customers predict that their annual usage requirements will likely grow through 2023, their peak day requirements are not projected to grow by a similar rate of increase. This is for two reasons: first, the increased annual usage is the result of adding additional daily shifts or adding production in weeks or months not previously utilized at 100% load factor (i.e. seasonal increases), and second, LV customers often take time to “grow” past an existing CD. Therefore, a certain pattern of therm usage will not necessarily equate with a commensurate level of growth in CD.

Load Profile vs MDFQ

Even though a monthly therm usage projection (i.e. load profile) is available for each customer, the IRP optimization model does not use the load profile for modeling purposes. The model instead uses the LV CD's because, as explained above, the LV customer group is not significantly weather sensitive so attempting to estimate daily usage using degree days, as is done for the core market, does not provide acceptable results. And without weather as the driver, it is difficult to estimate daily usage patterns. For these reasons it makes sense to use the customer CD as the daily requirement, as it reflects the known peak day obligation for every individual and each AOI. Most importantly, since Intermountain does not provide gas supply or interstate pipeline capacity for any of the transportation customers, the model does not need to project gas supply requirements for these customers but only the maximum amount of distribution capacity they will need on any given day.

Once the CD's are final, they are loaded directly into the optimization model by AOI and period. The optimization model also assumes that transport customers deliver an amount of zero cost gas supply equal to their aggregated CD for each transport rate class by AOI and period. That assumption allows the model to recognize that gas supply and/or interstate capacity requirements for the transport customers need to be delivered each day, but because it is not provided by Intermountain, there is no need to attempt to calculate an unknown cost that is meaningless to Intermountain.

System Reliability

It is important to note that before adding new firm load, engineering tests the system via its modeling system to determine whether or not the company could serve that load under design weather peak day loads before proceeding. That analysis is always completed prior to executing any firm contract for any new customer or an existing customer's expansion. Since the company knows the various parts of the system that may be at or nearing capacity constraints, those AOI's are given particular attention under load growth scenarios. This procedure assures current firm customers that new customers are not negatively affecting peak day deliverability.

General Assumptions

All current customers were assumed to remain on their current tariff and all forecast scenarios used the 2019 operating budget as a starting point. The IRP also calculated LV therm usage and MDFQ by AOI so that each geographic area of concern can be accurately modeled.

Base Case Scenario Summary

For the base case scenario, Intermountain assumed that the supply of natural gas remains plentiful and the price of natural gas stays competitive with other energy sources. The base case was compiled using historical usage and surveys with adjustments made to reflect known or probable changes of existing customers. The projected annual usage in the base case scenario increased by 6.6 million therms (0.5%) over the five-year period as seen in the table on the next page. The rate of projected annualized growth has slowed significantly from the last IRP largely due to slowing or negative growth in the potato processors and other food processors market segments.

Table 7: Large Volume Base Case Therms

	2019	2020	2021	2022	2023	Rate of Growth
Potato (A.)	111,649	112,620	108,620	108,770	108,870	-0.6%
Other Food, Dairy and Ag (B.)	155,304	156,860	157,541	159,922	159,988	0.7%
Chemical/Fertilizer (C.)	29,668	29,805	29,805	29,805	29,805	0.1%
Manufacturing (D.)	22,463	23,174	23,812	24,490	24,928	2.6%
Institutional (E.)	24,789	25,327	25,471	25,615	25,820	1.0%
Other (F.)	18,173	18,381	18,881	19,081	19,261	1.5%
Total Base Case	362,046	366,167	364,130	367,683	368,672	0.5%

A. The potato processors group is forecast to be relatively flat over the five-year period. Demand for potato products remains flat but supplies remain plentiful. Some market participants claim that some former potato acreage is being replaced with hops. No new plants are assumed in the forecast and most of the plants in this group are looking for ways to lower the overall cost of production, conserve resources and maximize efficiencies leading to a slight decline in projected usage. The decrease in usage is due to the projected closure of one facility in 2021.

B. The other food processing group is projected to see slight growth over the five-year period. While the huge increase in the sugar and other food processing segment over the past decade is projected to flatten, Intermountain still forecasts growth for dairy producers. The base case assumes one new dairy customer.

C. The three plants in the chemicals/fertilizers group will continue at current levels with nearly no projected growth in the forecast. The base case assumes no new customers.

D. The manufacturing group is expected to see strong growth. The growth is largely due to increases in electronics manufacturing companies and the addition of two new companies.

E. The institutional group is projected to grow at 1.0% a year, due mainly to new hospitals that have recently been built or will be built in the coming years.

F. The usage in the other group is projected to see some reasonably strong growth largely due to growth in customers using natural gas as a transportation fuel.

High Growth Scenario Summary

The high growth scenario figures incorporate usage data from the base case with adjustments for additional growth that are assumed to occur if the economy continues to expand at its recent pace. The LV volume in the high growth scenario is approximately 7% above the 2023 base case. The 32 million therm increase over the 2019 estimate of 362 million therms (2.1%) results from growth in every market segment. The following table summarizes the changes over this period:

Table 8: Large Volume High Growth Therms

	2019	2020	2021	2022	2023	Rate of Growth
Potato (A.)	111,649	114,420	114,920	116,070	116,170	1.0%
Other Food, Dairy and Ag (B.)	155,304	166,695	169,696	171,147	171,363	2.5%
Chemical/Fertilizer (C.)	29,668	29,805	29,805	29,805	32,305	2.2%
Manufacturing (D.)	22,463	23,174	23,812	24,490	24,928	2.6%
Institutional (E.)	24,789	28,080	28,403	28,397	28,872	3.9%
Other (F.)	18,173	19,032	19,565	19,774	19,967	2.4%
Total High Growth	362,046	381,206	386,201	389,683	393,605	2.1%

A. Potato production is up from the 2017 IRP projections, and the future shows steady growth for the potato industry. This scenario shows steady growth largely due to significant expansions at three existing facilities. Strong potato production assumes increasing demand, good quality and yield and higher prices. Very competitive natural gas prices keep these plants on gas rather than oil or alternative fuels. However, no new customers are assumed.

B. The other food processors are projected to show strong growth across the reporting periods. The assumptions include strong growth in the sugar industry, and strong growth and several plant expansions in the dairy industry. The meat and ag/feed industries remain relatively flat. Overall this segment assumes four new customers.

C. The chemical/fertilizer group is projected to increase due to the assumption of one new plant by 2023. The three existing plants show little growth over the IRP.

D. The manufacturing group is projected to have a strong increase over the period due to increases in high-tech manufacturing, plus the addition of one new plant.

E. The institutional group, which is made up of schools, hospital and tourism-based facilities is also projected to experience strong growth. This assumption is driven by the expectation of continuing cooler than normal weather, which affects this weather-sensitive group, and the addition of two new customers.

F. The other group is projected to grow slightly, with some increased usage at a greenhouse, and the addition of a new user. Usage will be relatively flat across the reporting period in the high growth scenario.

Low Growth Scenario Summary

The projected usage for the low growth scenario is based upon the assumption that the agricultural economy will be flat-to-declining with very little growth in sales and production. It is also assumed that natural gas prices will be relatively flat and see significant competition from renewables and other energy sources. With those assumptions, a downturn is projected beginning in 2020 that continues through 2023. The low growth scenario projections start 2% below 2019 with overall usage decreasing a projected 1.5% by 2023.

Table 9: Large Volume Low Growth Therms

	2019	2020	2021	2022	2023	Rate of Growth
Potato (A.)	111,649	109,720	107,670	107,070	106,170	-1.3%
Other Food, Dairy and Ag (B.)	155,304	150,695	140,695	140,695	140,695	-2.4%
Chemical/Fertilizer (C.)	29,668	29,805	29,805	29,805	29,805	0.1%
Manufacturing (D.)	22,463	23,094	22,694	22,494	22,494	0.0%
Institutional (E.)	24,789	23,019	22,949	22,944	22,939	-1.9%
Other (F.)	18,173	18,079	18,444	18,444	18,444	0.4%
Total Low Growth	362,046	354,412	342,257	341,452	340,547	-1.5%

A. The price of natural gas was assumed to be less competitive against the delivered price of alternative sources and global potato consumption is assumed to soften significantly. This segment, as a whole, generally looks at any way possible to conserve energy and make its plants more efficient. This scenario assumes the loss of one existing plant, softening at several other plants and no new customers.

B. The other food processing group is expected to soften significantly with large decreases in sugar processing, flat usage among the dairy customers and no new customers.

C. The projection for the chemical/fertilizer group remains flat with no new customers.

D. The manufacturing group is also projected to remain flat with some growth in high-tech companies that is offset by the loss of several of the smaller customers. Additionally, the low growth scenario assumes the loss of a few state or federal highway projects which leads to a contraction in usage among asphalt customers. However, this segment is still projected to add two smaller customers by 2023.

E. The projection of a decline for the institutional group is attributed to forecasted warmer than normal weather affecting universities, schools, and hospitals, as well as little growth in the tourism industry and the addition of only one small customer.

F. The other group's usage of natural gas is projected to remain mostly flat as the forecast assumes no growth in the transportation related customers as well as the loss of one smaller customer. Most of the loss is offset by the addition of a new customer in 2020.

LARGE VOLUME CUSTOMER SURVEY – COVER LETTER

July 16, 2018

Dear Intermountain Gas Customer

Intermountain Gas values you as a customer and we are committed to meeting your expectations of receiving reliable energy services to your facility. We continue to see strong and steady growth in natural gas usage from all sectors of our business. That growth coupled with the potential for extremely frigid winter weather underscores the importance of our long-term planning efforts.
The Idaho Public Utilities Commission (IPUC) requires Intermountain to file a bi-annual, long-term Integrated Resource Plan (IRP) that gives both the Commission and our customers a close-up view of our planning efforts. The IRP provides an opportunity for you to participate in the process and to assess our forecast including its inputs, underlying methodologies and conclusions. The IRP we file with the IPUC documents the entire process and it provides assurance to our customers that we utilize detailed, transparent and industry accepted practices as we plan to meet your energy needs in a prudent manner.

We are now beginning to prepare the data inputs for the 2019–2023 IRP. Our demand or usage forecast is the basis for the entire IRP and therefore it is critical that it be as accurate as possible. To this end, I am writing to request your assistance by providing projections of your facility's natural gas requirements for the next several years.

I have enclosed a survey form that requests information relative to projected changes in your facility's annual and peak day natural gas requirements and alternate fuel plans. To provide context, I have included actual annual and peak day therm use (where available) for the two most recent 12-month periods ending June 2018 and June 2017. I recognize the time required to complete this survey but including your projections in our IRP will improve its accuracy and I assure you that we do use the data you provide.

Please return your completed survey, including any comments or questions you may have, by August 17, 2018. To show my appreciation for your participating in our IRP forecast, if you return the completely filled-out survey by the August 17th deadline, I will enter your name in a raffle for one of three gifts: an Intermountain Gas branded Polo shirt, a box of Titleist PRO V1 golf balls or an Intermountain Gas branded baseball-type hat. Note only one entry per company will be entered into the raffle.

As always, any information you provide will be strictly confidential, will not be shared with any other entity and will be aggregated with data from other similar situated customers in any public filing. Should you have any questions or if I can be of assistance to you, please call me at my office (208-377-6118), my cell phone (208-850-2139) or you can always email me at dave.swenson@intgas.com.

I thank you in advance for your willingness to help.

David Swenson
Manager, Industrial Services
Intermountain Gas Company

Enclosures

Figure 17: Large Volume Customer Survey Cover Letter Sample

Intermountain Gas Company – 2019-2024 Large Volume Customer Survey

Company Name: [redacted] *Rate Class:* [redacted]
Account # [redacted] *Contract Expiration Date:* [redacted]
Street Address: [redacted] *Contract Demand (or MDFQ):* [redacted]
City/State/Zip: [redacted]

HISTORICAL INFORMATION

	Annual Therms	Winter Peak Day	Date of Peak Day
12 Months Ending June 2018	[redacted]	[redacted]	[redacted]
12 Months Ending June 2017	[redacted]	[redacted]	[redacted]

REQUESTED INFORMATION – PROJECTED THERMS

Description	2019	2020	2021	2022	2023	2024
Annual Therms						
Peak Day Therms						

What is the prime reason for the projected change in therm use? ____________

Are the 2019-24 therm use projections above lower than they otherwise might have been due to the use of an alternative energy source? ☐ Yes ☐ No
If yes, how much of your 2018 natural gas usage did alternative energy offset? Annual Therms= ____________ Peak Day Therms____________

What percent of your current peak day energy needs, served by natural gas, can be served by existing alternative fuel? ____________

What is your existing alternative source of energy? ☐ None ☐ Coal ☐ Oil ☐ Other (specify) ____________

If you are contemplating incorporating an alternative energy source, what is your preference? ☐ None ☐ Coal ☐ Oil ☐ Other (specify) ____________

Do you plan to employ energy saving or other conservation measures that will reduce your Therms of natural gas? ☐ Yes ☐ No
If yes, please estimate the reduction natural gas therms (therms or percent): Annual Therms = ____________ Peak Day Therms = ____________

What is the combined total of the input ratings for all natural gas-fired equipment? (circle correct units) ____________ **[btu/hr] [MMBtu/hr] [therms/hr] [scf/hr]**

Do you plan to install additional natural gas fired equipment through 2019? ☐ Yes ☐ No
If yes, what year do you expect to install ________ and what is the input rating? (circle correct units) ____________ **[btu/hr] [MMBtu/hr] [therms/hr] [scf/hr]**

Are there any additional service options would you like Intermountain to consider or do you have any suggestions for Intermountain that could help enhance its service?

ANY INFORMATION PROVIDED VIA THIS FORM WILL REMAIN CONFIDENTIAL WITH INTERMOUNTAIN GAS COMPANY
Please return via mail to 555 S Cole Road, Boise ID 83709 or email to Dave.Swenson@intgas.com by August 17, 2018

Figure 18: Large Volume Customer Survey Sample

Supply & Delivery Resources

Supply & Delivery Resources Overview

Once future load requirements have been forecasted, currently available supply and delivery resources are matched with demand to identify system deficits. Essential components considered when reviewing supply and delivery resources include identifying currently available supply resources, delivery capacity, and other resources that can offset demand such as energy efficiency programs or large volume customers with alternative fuel sources.

Supply and deliverability are considered by AOI to identify system constraints that result from forecasted demand. By comparing demand versus capacity for each AOI, the Company is better able to select capacity constraint solutions that consider cost effectiveness, operations and maintenance impacts, project viability, and future growth.

After analyzing resource requirements for each AOI, the data is aggregated to provide a total company perspective. Supply and delivery resources that are currently available are compared to the six total company demand scenarios that were established in the demand forecast. In the Load Demand Curves Section, beginning on page 90, demand and capacity are compared to clearly identify deficits. Alternative solutions for how the deliverability deficits will be resolved are considered in the Optimization and Planning Results sections of this Integrated Resource Plan.

Traditional Supply Resources

Overview

Natural gas is a fundamental fuel for Idaho's economic and environmental future: heating our homes, powering businesses, moving vehicles and serving as a key component in many of our most vital industrial processes. The natural gas marketplace continues to change but Intermountain's commitment to act with integrity to provide secure, reliable and price-competitive firm natural gas delivery to its customers has not. In today's energy environment, Intermountain bears the responsibility to structure and manage a gas supply and delivery portfolio that will effectively, efficiently, reliably and with best value meet its customers' year-round energy needs. Through its long-term planning, Intermountain continues to identify, evaluate and employ best-practice strategies as it builds a portfolio of resources that will provide the value of service that its customers expect.

The Traditional Supply Resources Section outlines the energy molecule and related infrastructure resources upstream of Intermountain's distribution system necessary to deliver natural gas to the Company's distribution system. Specifically included in this discussion is the natural gas commodity (or the gas molecule), various types of storage facilities and interstate gas transportation pipeline capacity. This section will identify and discuss the supply, storage and transportation capacity resources available to Intermountain and how they may be employed in the Company's portfolio approach to gas delivery management.

Background

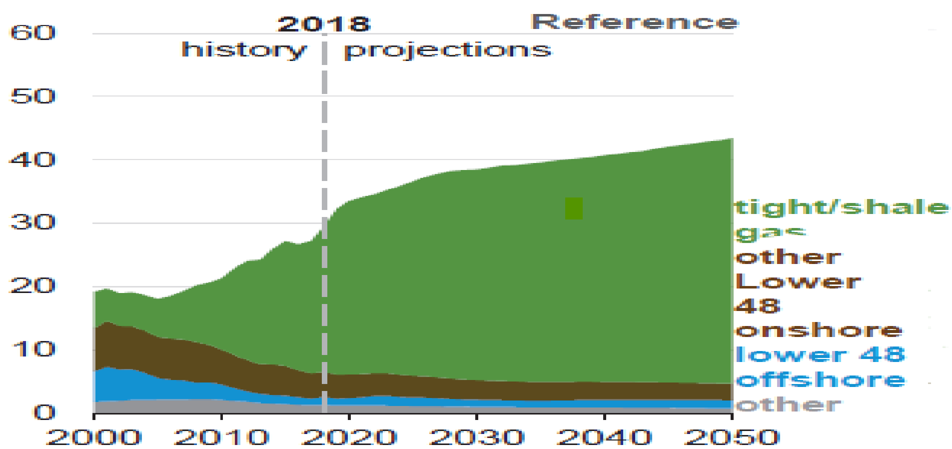
The procurement and distribution of natural gas is in concept a straightforward process. It simply follows the movement of gas from its source through processing, gathering and pipeline systems to end-use facilities where the gas is ultimately ignited and converted into thermal energy. Natural gas is a fossil fuel; a naturally occurring mixture of combustible gases, principally methane, found in porous geologic formations beneath the surface of the earth. It is produced or extracted by drilling into those underground formations or reservoirs and then moving the gas through gathering systems and pipelines to customers in often far away locations.

Intermountain is fortunate to be located between two prolific gas producing regions in North America. The first, the Western Canadian Sedimentary Basin (WCSB) in Alberta and British Columbia supplies approximately 79% of Intermountain's natural gas. The other region, known as the Rockies, includes many different producing basins in the states of Wyoming, Colorado and Utah where the remainder of the Company's supplies are sourced. The Company also utilizes storage facilities to store natural gas supply during the summer when prices are traditionally lower and save it for use during the winter to offset higher seasonal pricing.

Intermountain's access to the gas produced in these basins is wholly dependent upon the availability of pipeline transportation capacity to move gas from those supply basins to Intermountain's distribution system. The Company is fortunate, in that the interstate pipeline that runs through Intermountain's service territory is a bi-directional pipeline. This means it can bring gas from the north or south. Having the bi-directional flow capability allows Intermountain's customers to benefit from the least cost gas pricing in most situations and ample capacity to transport natural gas to Intermountain's citygates. A basic discussion of gas supply, storage and interstate transportation capacity resources follows.

Gas Supply Resource Options

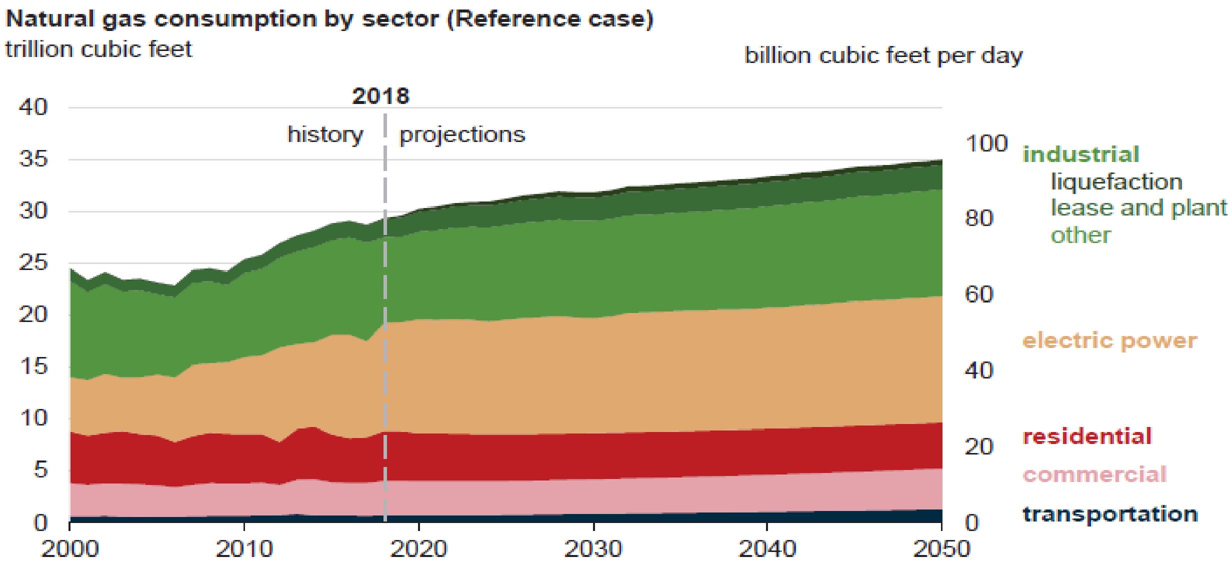
Over the past few years, advances in technology have allowed for the discovery and development of abundant supplies of natural gas within shale plays across the United States and Canada. This shale gas revolution has changed the energy landscape in the United States. Natural gas production levels continue to surpass expectations despite low gas prices and concerns about shale production techniques (See Figure 19 below).



Source: EIA AEO2019

Figure 19: Natural Gas Sources

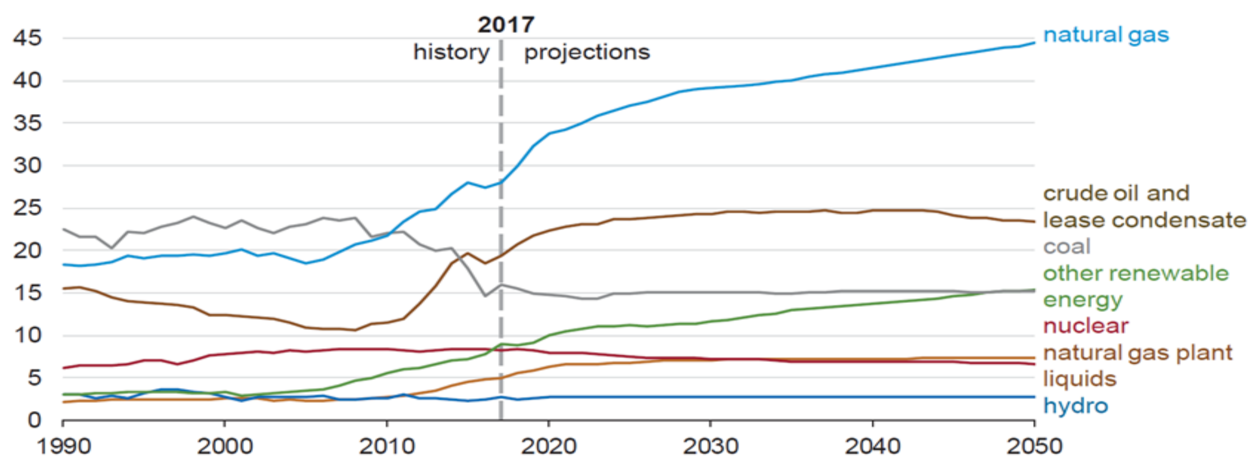
Projected low prices for natural gas have made it a very attractive fuel for natural gas fired electric generation as utilities are replacing coal-fired generation. Combine this with the industrial sector's post-recession recovery as they take advantage of low natural gas prices, and the result is a significant change in demand loads. See Figure 20 on the next page for consumption by sector, 2000-2050.



Source: EIA AEO2019

Figure 20: Natural Gas Consumption by Sector

Improved technologies for finding and producing nonconventional gas supplies have led to dramatic increases in gas supplies. Figure 21 below shows that shale gas production is not only replacing declines in other sources but is projected to increase total annual production levels through 2050.



Source: EIA AEO2018

Figure 21: Shale Gas Production Trend

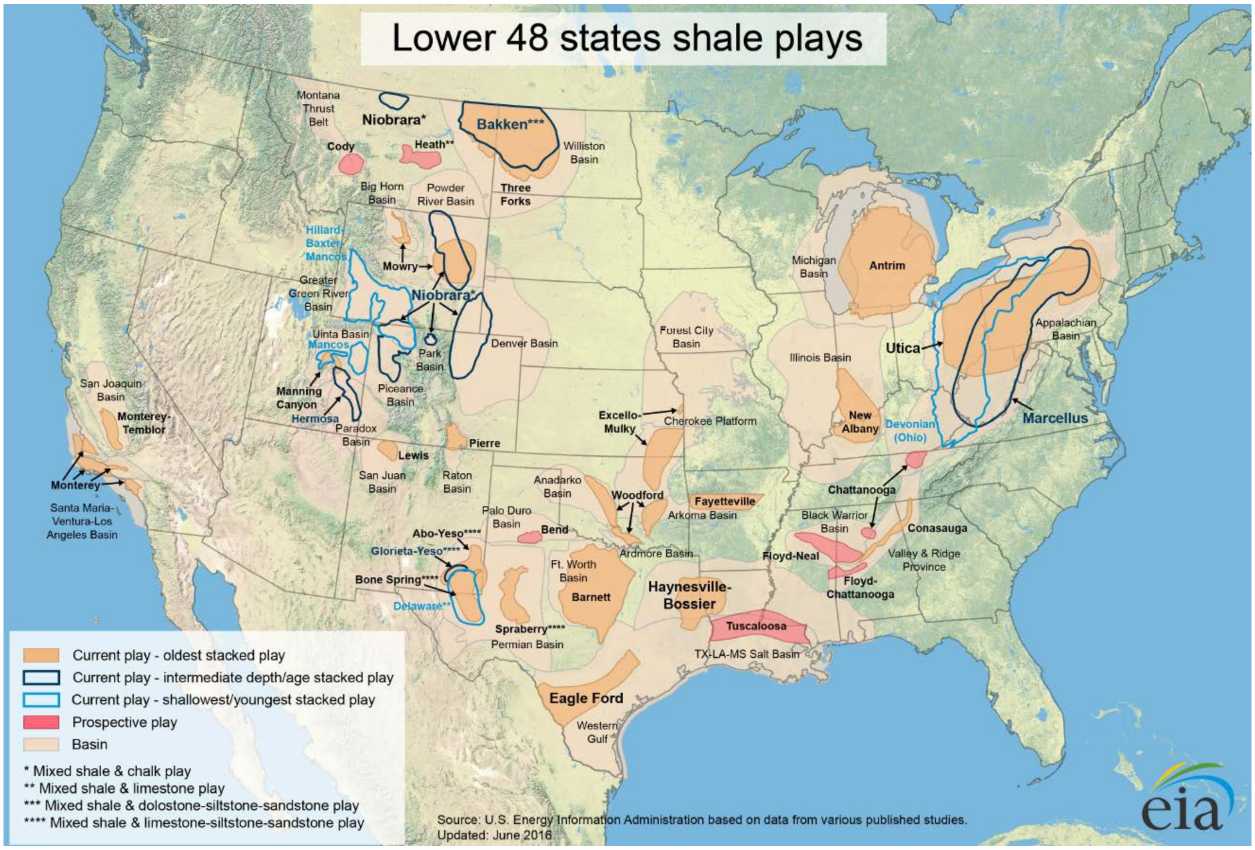
While natural gas prices continue to exhibit volatility from both national, global and regional perspectives, the laws of supply and demand clearly govern the availability and pricing of natural gas. Recent history shows that periods of growing demand tends to drive prices up which in turn generally results in consumers seeking to lower consumption. At the same time, producers typically increase investment in activities that will further enhance production. Thus, falling demand coupled with increasing supplies tends to swing prices lower. This in turn leads to falling supplies and increased demand which begins the cycle anew (see Figure 21 on the previous page for shifting demand). Finding equilibrium in the market has been challenging for all market participants but at the end of the day, the competitive market clearly works; the challenge is avoiding huge swings that result in either demand destruction or financial distress in the exploration and production business.

Driven by technological breakthroughs in unconventional gas production, major increases in North American natural gas reserves and production have led to supply growth significantly outgaining forecasts in recent years. Thus, natural gas producers have sought new and additional sources of demand for the newfound volumes. The abundant supply of natural gas discussed above has resulted in the United States becoming a net exporter of liquefied natural gas (LNG) versus the expectation of it being a net importer several years ago. The currently operational LNG export facilities in the United States together with additional new facilities on the drawing board will result in a significant new market for the incremental gas supplies being developed and produced.

Shale Gas

Shale gas has changed the face of U.S. energy. Today, reserve and production forecasts predict ample and growing gas supplies through 2050 because of shale gas. The fact that shale gas is being produced in the mid-section of the U.S has displaced production from more traditional supply basins in Canada and the Gulf Coast. There have been some perceived environmental issues relating to shale production, but most studies indicate that if done properly, shale gas can be produced safely. Customers now enjoy the lowest natural gas prices in years due to the increased production of shale gas.

Per the EIA, the portion of U.S. energy consumption supplied by domestic production has been increasing since 2005, when it was at its historical low point (69%). Since 2005, production of domestic resources, particularly natural gas and crude oil, have been increasing because of shale gas production. Figure 22 on the next page identifies the shale plays in the lower 48 states.



Source: Energy Information Administration based on data from various published studies.

Updated June 2016.

Figure 22: US Lower 48 States Shale Plays

Supply Regions

As previously stated, Intermountain's natural gas supplies are obtained primarily from the WCSB and the Rockies. Access to those abundant supplies is completely dependent upon the amount of firm transportation capacity held on the applicable pipelines for delivering such gas to Intermountain’s service territory. Transportation capacity is so important that a discussion of the Company’s purchases of natural gas cannot be fully explored without also addressing pipeline capacity. On average, Intermountain currently purchases approximately 79% of its gas supplies from the WCSB and the remainder from the Rockies. However, due to certain flexibility in Intermountain’s firm transportation portfolio, it is afforded the opportunity to procure some portion of its annual needs from supply basins which may offer lower cost gas supplies in the future.

Alberta

Alberta supplies are delivered to Intermountain via two Canadian pipelines (TransCanada Energy via Nova, and Foothills pipelines) and two U.S. pipelines (Gas Transmission Northwest (GTN), and Williams Northwest Pipeline, (NWP)) as seen below in Figure 23.

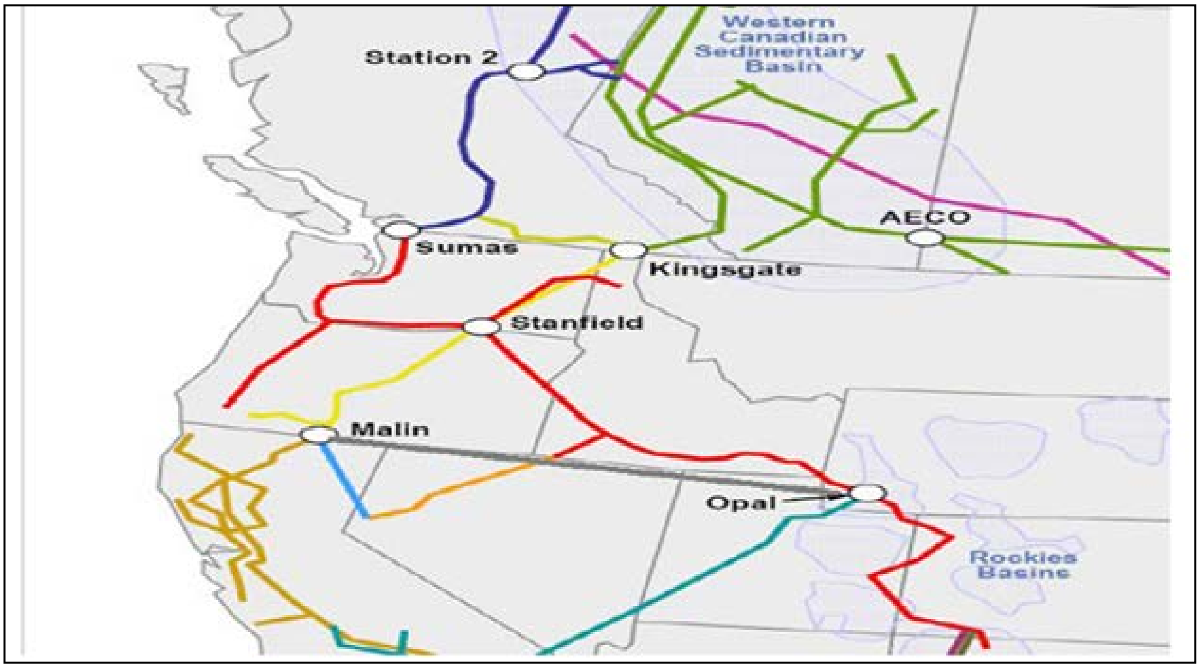


Figure 23: Supply Pipeline Map

Intermountain will continue to utilize a significant amount of Alberta supplies in its portfolio. The Stanfield interconnect between NWP and GTN offers operational reliability and flexibility over other receipts points both north and south. Where these supplies once amounted to a minor portion of the Company's portfolio, today's purchases amount to over 76% of the Company's annual purchases.

British Columbia

British Columbia has traditionally been a source of competitively priced and abundant gas supplies for the Pacific Northwest. Gas supplies produced in the province are transported by Spectra Energy to an interconnect with NWP near Sumas, WA. Historically, much of the provincial supply had been somewhat captive to the region due to the lack of alternative pipeline options into eastern Canada or the midwestern U.S. However, pipeline expansions into these regions have eliminated that bottleneck. Although these supplies must be transported long distances in Canada and over an international border, there have historically been few political or operational constraints to impede ultimate delivery to Intermountain's citygates. An exception to pipeline constraints occurred during the winter of 2018 when Enbridge had a major disruption from a pipeline rupture that occurred on October 9, 2018. The ensuing winter months saw a reduction in capacity for British Columbia gas supplies to be delivered at Sumas due to the incident and pipeline integrity testing required by the National Energy Board in Canada to ensure safe and reliable pipeline conditions. Those interruptions along with a cold and long winter had a significant impact on pricing. However, due to the predominance of Intermountain's supplies coming from Alberta and delivered via GTN at Stanfield, coupled with Intermountain's ability to utilize its liquefied natural gas storage contracts on NWP's system, it was able mitigate the impact to its customers of the dramatic short-term price increases.

Rockies

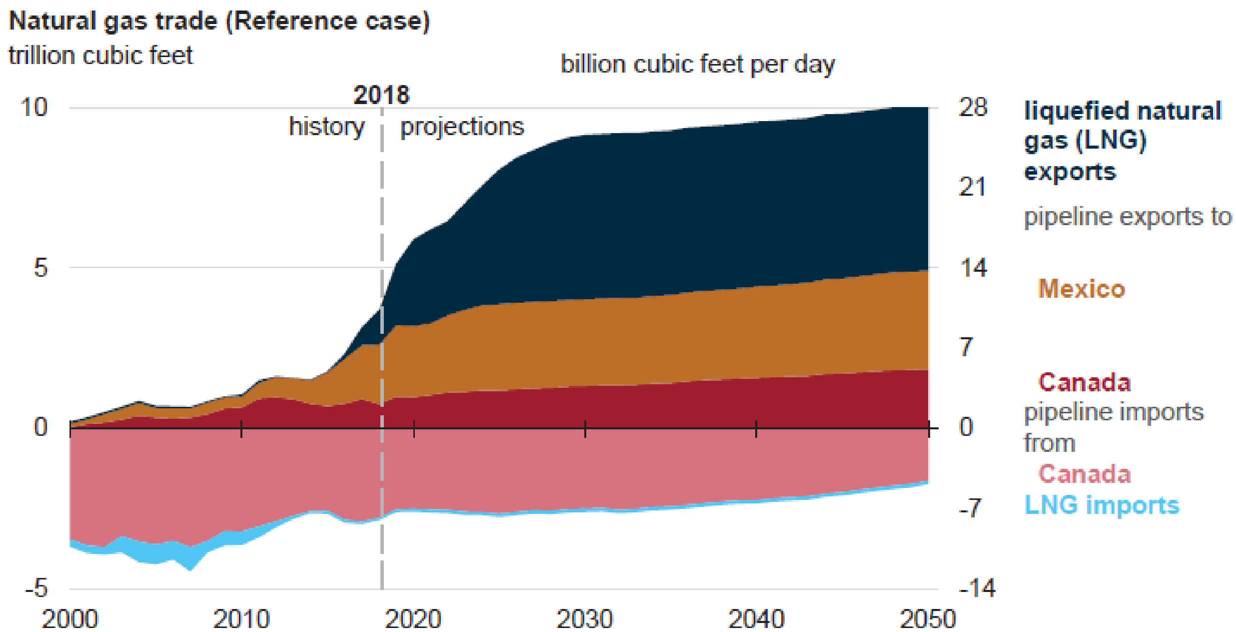
Rockies supply has been the second largest source of supply for Intermountain because of the ever-growing reserves and production from the region coupled with firm pipeline capacity available to Intermountain. Additionally, Rockies supplies have been readily available and highly reliable. Historically, pipeline capacity to move Rockies supplies out of the region has been limited, which has forced producers to compete to sell their supplies to markets with firm pipeline takeaway capacity. Several pipeline expansions out of the Rockies have greatly minimized or eliminated most of the capacity bottlenecks, so these supplies can now more easily move to higher priced markets found in the Midwest, East or in California. Consequently, even though growth in Rockies reserves and production continues at a rapid pace reflecting increased success in finding tight sand, coal seam and shale gas, the more efficient pipeline system has largely eliminated the price advantage that Pacific Northwest markets had enjoyed.

While Intermountain's firm transportation portfolio does provide for accessing Rockies gas supplies, and as discussed above, Intermountain has chosen today and for the foreseeable future to purchase the predominance of its annual supply needs out of Alberta due to the lower cost environment from that supply basin. However, due to its close proximity, Intermountain does purchase the lower cost Rockies gas supplies in the summer for injection into its Clay Basin storage accounts located in North Eastern Utah.

Export LNG

Growth in North American natural gas supplies (see Shale Gas above) has eliminated discussion about LNG import facilities. Because LNG is traded on the global market, where prices are typically tied to oil, U.S. produced LNG is very competitive. LNG exports now play a role in the overall supply portfolio of U.S. supply, with several new LNG export facilities proposed or in production. The U.S. is now a net exporter of natural gas in large part due to LNG.

Figure 24 below identifies LNG imports by year going back to 2000. A downward trend since 2007 is apparent. In 2015 LNG imports were at their lowest levels since 2000 and trending to net exports. The projection still shows a large growth in the LNG export market.



Source: EIA AEO2019

Figure 24: Natural Gas Trade

Types of Supply

There are essentially two main types of gas supply: firm and interruptible. Firm gas commits the seller to make the contracted amount of gas available each day during the term of the contract and commits the buyer to take that gas on each day. The only exception would be force majeure events where one or both parties cannot control external events that make delivery or receipt impossible. Interruptible or best efforts gas supply typically is bought and sold with the understanding that either party, for various reasons, does not have a firm or binding commitment to take or deliver the gas.

Intermountain builds its supply portfolio on a base of firm, long-term gas supply contracts but includes all the types of gas supplies as described below:

1. Long-term: gas that is contracted for a period of over one year.

2. Short-term: gas that is often contracted for one month at a time.

3. Spot: gas that is not under a long-term contract; it is generally purchased in the short-term on a day ahead basis for day gas and during bid week prior to the beginning of the month for monthly spot gas.

4. Winter Baseload: gas supply that is purchased for a multi-month period most often during winter or peak load months.

5. Citygate Delivery: natural gas supply that is bundled with interstate transportation capacity and delivered to the Intermountain citygate meaning that it does not use the Company's existing transportation capacity.

Pricing

The Company does not currently utilize NYMEX based products to hedge forward prices but buys a portion of its gas supply portfolio at fixed priced forward physicals. Purchasing fixed price physicals provides the same price protection without the credit issues that come with financial instruments. A certain level of fixed price contracts allows Intermountain to participate in the competitive market while avoiding upside pricing exposure. While the Company does not utilize a fully mechanistic approach, its Gas Supply Oversight Committee meets frequently to discuss all gas portfolio issues which helps to provide stable and competitive prices for its customers.

For IRP purposes, the Company develops a base, high, and low natural gas price forecast. Demand, oil price volatility, the global economy, electric generation, opportunities to take advantage of new extraction technologies, hurricanes and other weather activity will continue to impact natural gas prices for the foreseeable future. Intermountain considers price forecasts from several sources, such as Wood Mackenzie, EIA, S&P Global, NYMEX Henry Hub, Northwest Power and Conservation Council, as well as Intermountain's own observations of the market to develop the low, base, and high price forecasts. For optimization purposes, Intermountain uses pricing forecasts from four sources for the AECO, Rockies and Sumas pricing points along with a proprietary model based upon those forecasts. The selected forecast includes a monthly base price projection for each of the three purchase points, as seen in Figure 25.

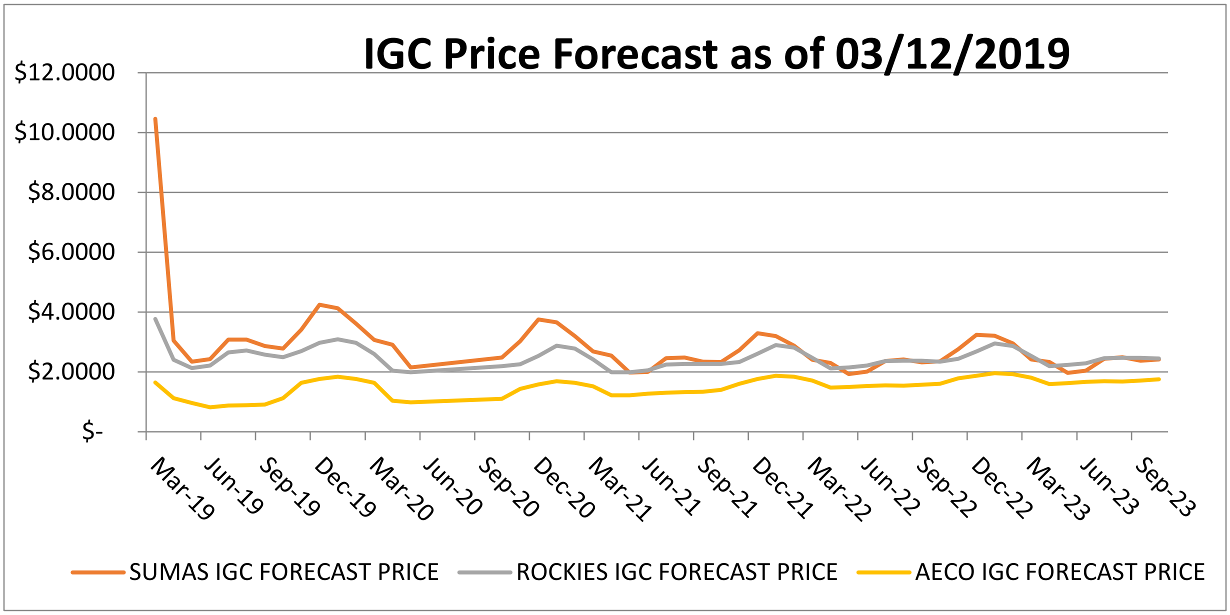


Figure 25: Intermountain Price Forecast as of 03/12/2019

Storage Resources

The production of natural gas and the amount of available pipeline capacity are very linear in nature; changes in temperatures or market demand does not materially affect how much of either is available daily. As the Resource Optimization Section discusses (see page 111), a peak day only occurs for, at most, a few days out of the year. The demand curve then drops rapidly back to more normal winter supply levels before dropping off drastically headed into the summer months. Attempting to serve the entire year at levels required to meet peak demand would be enormously expensive. So, the ability to store natural gas during periods of non-peak demand for use during peak periods is a cost-effective way to fill the gap between static levels of supply and capacity versus the non-linear demand curve.

Intermountain utilizes storage capacity in four different facilities from western Washington to northeastern Utah. Two are operated by NWP: one is an underground project located near Jackson Prairie, WA (JP) and the other is a liquefied gas (LS) facility located near Plymouth, WA (See map, Figure 26). Intermountain also leases capacity from Dominion Energy Pipeline's Clay Basin underground storage field and operates its own LNG facility located in Nampa, ID. Additionally, Intermountain owns a satellite LNG facility in Rexburg, ID. The Rexburg facility is supplied with LNG from the Nampa LNG facility.

All storage resources allow Intermountain to inject gas into storage during off-peak periods and then hold it for withdrawal whenever the need arises. The advantage is three-fold: 1) the Company can serve the extreme winter peak while minimizing year-round firm gas supplies; 2) storage allows the Company to minimize the amount of the year-round interstate capacity resources required and helps it to use existing capacity more efficiently; and 3) storage provides a natural price hedge against the typically higher winter gas prices. Thus, storage allows the Company to meet its winter loads more efficiently and in a cost-effective manner.

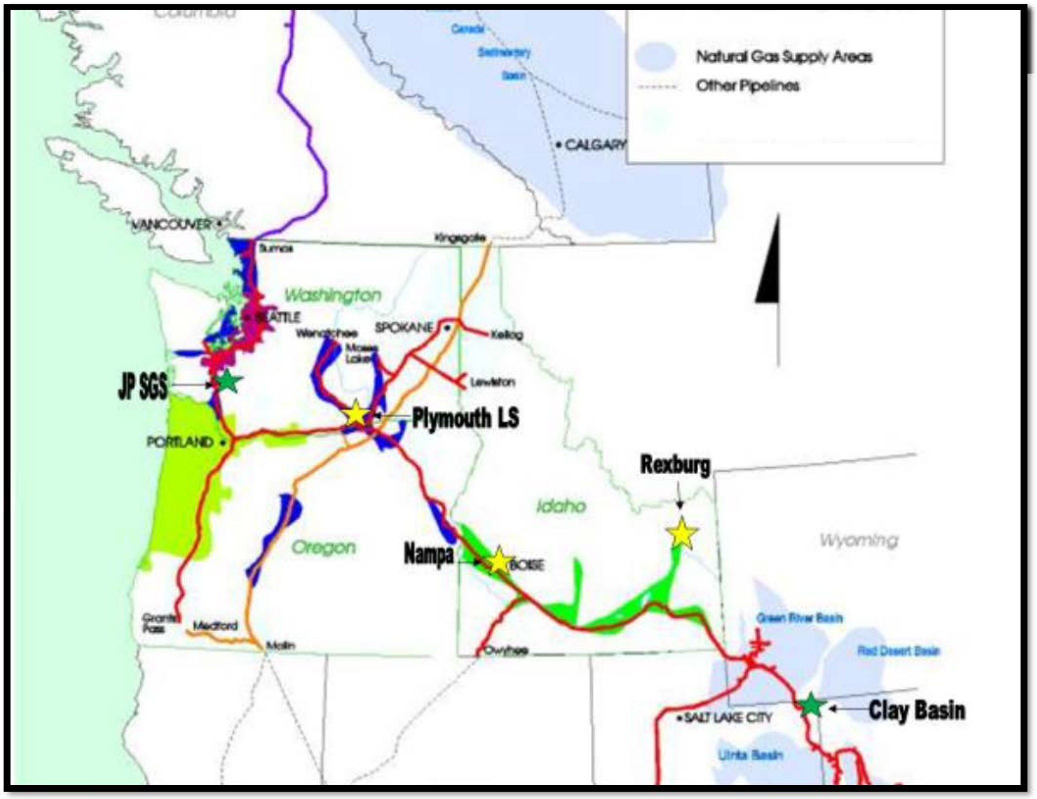


Figure 26: Intermountain Storage Facilities

Liquefied Storage

Liquefied storage facilities make use of a process that super cools and liquefies gaseous methane under pressure until it reaches approximately minus 260°F. LNG occupies only one-six-hundredth the volume compared to its gaseous state, so it is an efficient method for storing peak requirements. LNG is also non-toxic; it is non-corrosive and will only burn when vaporized to a 5-15% concentration with air. Because of the characteristics of liquid, its natural propensity to boil-off and the enormous amount of energy stored, LNG is normally stored in man-made steel tanks.

Liquefying natural gas is, relatively-speaking, a time-consuming process, the compression and storage equipment is costly, and liquefaction requires large amounts of added energy. It typically requires as much as one unit of natural gas burned as fuel for every three to four units liquefied. Also, a full liquefaction cycle may take five to six months to complete. Because of the high cost and length of time involved in filling a typical LNG facility, they are usually cycled only once per year and are reserved for peaking purposes. This makes the unit cost of the gas withdrawn somewhat expensive when compared to other options.

Vaporization, or the process of changing the liquid back into the gaseous state, on the other hand, is a very efficient process. Under typical atmospheric and temperature conditions, the natural state of methane is gaseous and lighter than air as opposed to the dense state in its liquid form. Consequently, vaporization requires little energy and can happen very quickly. Vaporization of LNG is usually accomplished by utilizing pressure differentials by opening and closing valves in concert with the use of some hot-water bath units. The high-pressure LNG is vaporized as it is warmed and is then allowed to push itself into the lower pressure distribution system. Potential LNG daily withdrawal rates are normally large and, as opposed to the long liquefaction cycle, a typical full withdrawal cycle may last 10 days or less at full rate. Because of the cost and cycle characteristics, LNG withdrawals are typically reserved for needle peaking during very cold weather events or for system integrity events.

Neither of the two LNG facilities utilized by Intermountain requires the use of year-round transportation capacity for delivery of withdrawals to Intermountain's customers. The Plymouth facility is bundled with redelivery capacity for delivery to Intermountain and the Nampa and Rexburg LNG tank withdrawals go directly into the Company's distribution system. The IRP assumes liquid storage will serve as a needle peak supply.

Underground Storage

This type of facility is typically found in naturally occurring underground reservoirs or aquifers (e.g. depleted gas formations, salt domes, etc.) or sometimes in man-made caverns or mine shafts. These facilities typically require less hardware compared to LNG projects and are usually less expensive to build and operate than liquefaction storage facilities. In addition, commodity costs of injections and withdrawals are usually minimal by comparison. The lower costs allow for the more frequent cycling of inventory and in fact, many such projects are utilized to arbitrage variations in market prices.

Another material difference is the maximum level of injection and withdrawal. Because underground storage involves far less compression as compared to LNG, maximum daily injection levels are much higher, so a typical underground injection season is much shorter, typically lasting only three to four months. But the lower pressures also mean that maximum withdrawals are typically much less than liquefied storage at maximum withdrawal. So, it could take 35 days or more to completely empty an underground facility. The longer withdrawal period and minimal commodity costs make underground storage an ideal tool for winter baseload or daily load balancing, and therefore, Intermountain normally uses underground storage before liquid storage is withdrawn. Underground storage is not ideal for delivering a large amount of gas quickly, however, so LNG is a better solution for satisfying a peak situation.

Intermountain contracts with two pipelines for underground storage: Dominion Energy for capacity at its Clay Basin facility in northeastern Utah and NWP for capacity at its Jackson Prairie facility in Washington. Clay Basin provides the Company with the largest amount of seasonal storage and daily withdrawal. However, since Clay Basin is not bundled with redelivery capacity, Intermountain must use its year-round capacity when these volumes are withdrawn. For this reason, the Company normally uses Clay Basin withdrawals during the November to March winter period to satisfy baseload needs.

Just like NWP's Plymouth LS facility, NWP's JP storage is bundled with redelivery capacity so Intermountain typically layers JP withdrawals between Clay Basin and its LNG withdrawals. The IRP uses Clay Basin as a winter baseload supply and JP is used as the first layer of peak supply. Table 10 below outlines the Company's storage resources for this IRP.

Table 10: Storage Resources

Facility	Seasonal Capacity	Daily Withdrawal Max Vol	Daily Withdrawal % of 2019 Peak	Daily Injection Max Vol	Daily Injection # of Days	Redelivery Capacity
Nampa	580,000	60,000	14%	3,500	166	None
Plymouth	1,475,135	155,175	36%	7,721	191	TF-2
Subtotal Liquid	2,055,135	215,175	50%	11,221		
Jackson Prairie	1,092,099	30,337	7%	30,337	36	TF-2
Clay Basin	8,413,500	70,114	16%	69,857	120	TF-1
Subtotal Underground	9,505,599	100,451	23%	100,194		
Grand Total	11,560,734	315,626	73%	111,415		

All the storage facilities require the use of Intermountain's every-day, year-round capacity for injection or liquefaction. Because injections usually occur during the summer months, use of year-round capacity for injections helps the Company make more efficient use of its every-day transport capacity and term gas supplies during those off-peak months when the core market loads are lower.

Nampa LNG Plant

The primary purpose of the Nampa LNG plant is to supplement gas supply onto Intermountain Gas' distribution system. The Nampa LNG Plant can store up to 600 million cubic feet of natural gas in liquid form and can re-gasify back into Intermountain's system at a rate of approximately 60 million cubic feet per day.

During a needle peak event the plant is able to supplement supply during gas storage shortages or transportation restrictions into Idaho, and the plant has the added benefit of supplying natural gas directly into the connected Canyon County and Ada County distribution systems without use of interstate pipeline transportation, which eliminates another risk variable typically associated with gas supply. Compressed natural gas is not a feasible option for gas supply, thus making the plant a more valuable resource to the company.

The Nampa LNG plant typically performs liquefaction operations during non-peak weather times of the year, resulting in lower priced natural gas going into liquid storage, and providing potential cost savings when re-gasification occurs during peak cold weather events, gas supply shortages and interstate transportation restrictions.

Storage Summary

The Company generally utilizes its diverse storage assets to offset winter load requirements, provide peak load protection and, to a lesser extent, for system balancing. Intermountain believes that the geographic and operational diversity of the four facilities utilized offers the Company and its customers a level of efficiency, economics and security not otherwise achievable. Geographic diversity provides security should pipeline capacity become constrained in one particular area. The lower commodity costs and flexibility of underground storage allows the Company flexibility to determine its best use compared to other supply alternatives such as winter baseload or peak protection gas, price arbitrage or system balancing.

Interstate Pipeline Transportation Capacity

As discussed earlier, Intermountain is dependent upon firm pipeline transportation capacity to move natural gas from the areas where it is produced, to end-use customers who consume the gas. In general, firm transportation capacity provides a mechanism whereby a pipeline will reserve the right, on behalf of a designated and approved shipper, to receive a specified amount of natural gas supply delivered by that shipper, at designated receipt points on its pipeline system and subsequently redeliver that volume to delivery point(s) as designated by the shipper.

Intermountain holds firm capacity on four different pipeline systems including NWP. NWP is the only interstate pipeline which interconnects to Intermountain's distribution system, meaning that Intermountain physically receives all gas supply to its distribution system (other than Nampa LNG) via citygate taps with NWP. Table 11 on the next page summarizes the Company's year-round capacity on NWP (TF-1) and its storage specific redelivery capacity (TF-2). Between the amount of capacity Intermountain holds on the GTN, Foothills, and Nova pipelines and firm-purchase contracts at Stanfield, it controls enough capacity to deliver a volume of gas commensurate with the Company's Stanfield takeaway capacity on NWP. Upstream pipelines bring natural gas from the production fields in Canada to the interconnect with NWP.

Intermountain has historically contracted a portion of its firm transportation on NWP through long-term segmented capacity contracts with third parties. As those contracts near their expiration dates, Intermountain was able to negotiate contracts to replace the expiring capacity with firm NWP transportation capacity contracted directly between Intermountain and NWP. Additionally, Intermountain was able to extend its existing NWP transport agreements as well as its Plymouth storage agreements. Until the existing capacity expires in 2020 and 2025, Intermountain will hold some excess capacity. To mitigate this situation, Intermountain was able negotiate a reduced rate for the new capacity until the existing capacity expires. Intermountain also plans to release the capacity to willing buyers on a short-term basis. The capacity releases will generate credits for Intermountain's customers that will help to additionally offset the costs of the capacity until the existing contracts expire. This capacity restructuring will allow Intermountain to continue to provide its customers the safe, reliable, and economically priced service they expect.

Table 11: Northwest Pipeline Transport Capacity

City Gate Delivery Quantity (MMBtu per day)	2019	2020	2021	2022	2023
TF-1 Capacity -					
Sumas Base Capacity	90,941	90,941	90,941	90,941	90,941
Sumas Segmentation and Release	(90,941)	(90,941)	(90,941)	(90,941)	(90,941)
Sumas Winter Only Capacity	3,000	3,000	3,000	3,000	3,000
Stanfield Base Capacity	88,175	105,624	105,624	105,624	130,624
Stanfield Capacity Via Segmentation	90,941	90,941	90,941	90,941	90,941
Rockies	97,478	97,478	97,478	97,478	97,478
Total TF-1 Capacity	279,594	297,043	297,043	297,043	297,043
City Gate Supply	18,056	18,056	-	-	-
Total City Gate Delivery Before TF-2	297,650	315,099	297,043	297,043	297,043
TF-2 Capacity -					
Plymouth (LS)	155,175	155,175	155,175	155,175	155,175
Jackson Prairie (JP)	30,337	30,337	30,337	30,337	30,337
Total TF-2 Capacity	185,512	185,512	185,512	185,512	185,512
Nampa LNG (does not include Rexburg)	60,000	60,000	60,000	60,000	60,000
Total City Gate Delivery	543,162	560,611	542,555	542,555	542,555

Northwest Pipeline's facilities essentially run from the Four Corners area north to western Wyoming, across southern Idaho to western Washington. The pipeline then continues up the I-5 corridor where it interconnects with Spectra Energy, a Canadian pipeline in British Columbia, near Sumas, Washington. The Sumas interconnect receives natural gas produced in British Columbia. Gas supplies produced in the province of Alberta are delivered to NWP via Nova, Foothills and then GTN near Stanfield, Oregon. NWP also connects with other U.S. pipelines and gathering systems in several western U.S. states (Rockies) where it receives gas produced in basins located in Wyoming, Utah, Colorado and New Mexico. The major pipelines in the Pacific Northwest, several of which NWP interconnects with can be seen below (Figure 27).

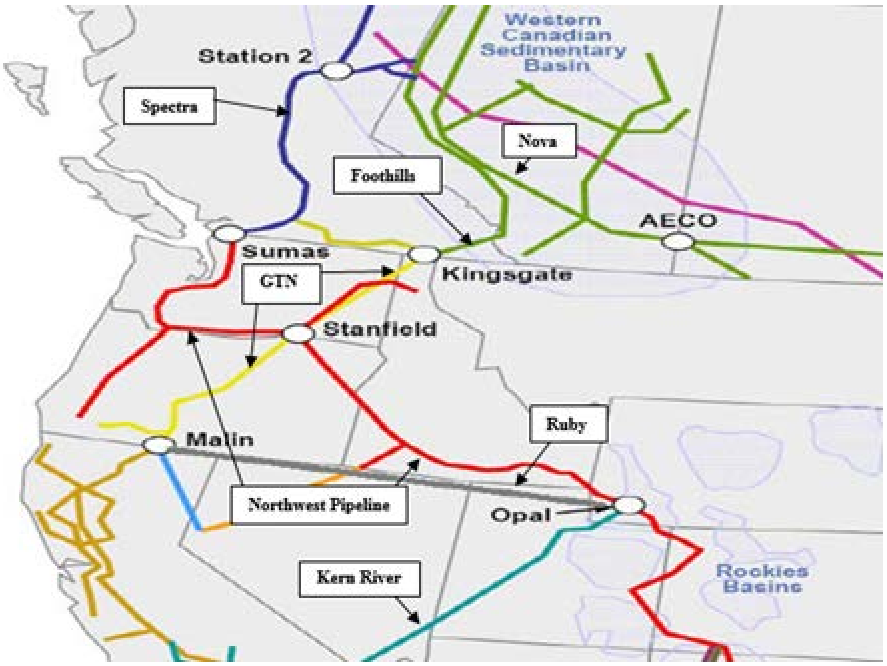


Figure 27: Pacific Northwest Pipelines Map

Because natural gas must flow along pipelines with finite flow capabilities, demand frequently cannot be met from a market's preferred basin. Competition among markets for these preferred gas supplies can cause capacity bottlenecks and these bottlenecks often result in pricing variations between basins supplying the same market area. In the short to medium term, producers in constrained basins invariably must either discount or in some fashion differentiate their product to compete with other also constrained supplies. In the longer run however, disproportionate regional pricing encourages capacity enhancements on the interstate pipeline grid, from producing areas with excess supply, to markets with constrained delivery capacity. Such added capacity nearly always results in a more integrated, efficient delivery system that tends to eliminate or at least minimize such price variances.

Consequently, new pipeline capacity - or expansion of existing infrastructure – in western North America has increased take-away capacity out of the WCSB and the Rockies, providing producers with access to higher priced markets in the East, Midwest and in California. Therefore, less-expensive gas supplies once captive to the northwest region of the continent, now have greater access to the national market resulting in less favorable price differentials for the Pacific Northwest market. Today, wholesale prices at the major trading points supplying the Pacific Northwest region (other than Alberta supplies) are trending towards equilibrium. At the same time, new shale gas production in the mid-continent is beginning to displace traditionally higher-priced supplies from the Gulf coast which, from a national perspective, has been causing an overall softening trend in natural gas prices with less regional differentials.

Today, Intermountain and the Pacific Northwest are in an increasingly mega-regional marketplace where market conditions across the continent - including pipeline capacities - can, and often do, affect regional supply availability and pricing dynamics. Natural gas supplies are readily available today and pricing dynamics show a continued price softening in the short term with price stability or minimal price increases in the longer term. Alberta gas supplies continue to be very price competitive and Intermountain has contracted for its Alberta based supplies for now five-years into the future.

Supply Resources Summary

Because of the dynamic environment in which it operates, the Company will continue to evaluate customer demand to provide an efficient mix of supply resources to meet its goal of providing reliable, secure, and economic firm service to its customers. Intermountain actively manages its supply and delivery portfolio and consistently seeks additional resources where needed. The Company actively monitors natural gas pricing and production trends to maintain a secure, reliable and price competitive portfolio and seeks innovative techniques to manage its transportation and storage assets to provide both economic benefits to customers and operational efficiencies to its interstate and distribution assets. The IRP process culminates with the optimization model that helps to ensure that the Company’s strategies to meet its traditional gas supply goals are based on sound, real-world, economic principles (see the Optimization Model Section beginning on page 86).

Capacity Release & Mitigation Process

Overview

Capacity release was implemented by FERC to allow markets to more efficiently utilize pipeline capacity. This mechanism allows a shipper with any unused capacity to auction the excess to another shipper that offers the highest bid. Thus, capacity that would otherwise sit idle can be used by a replacement shipper. The result is a more efficient use of capacity as replacement shippers maximize annualized use of existing capacity. One effect of maximizing the utilization of existing capacity is that pipelines are less inclined to build new capacity until the market recognizes that it is really needed and is willing to pay for new infrastructure. However, a more fully utilized pipeline can also mean existing shippers have less operational flexibility.

Intermountain has and continues to be active in the capacity release market. Intermountain has obtained significant amounts of unutilized capacity mitigation on NWP and GTN via capacity releases. The Company frequently releases seasonal and/or daily capacity during periods of reduced demand. Intermountain also utilizes a specific type of capacity release called segmentation to convert capacity from Sumas to Idaho into two paths of Sumas to Stanfield and Stanfield to Idaho. Intermountain uses the Stanfield to Idaho component to take delivery of the lower cost AECO gas supplies that are delivered by GTN to the interconnect with NWP at Stanfield. IGI Resources, Inc. (IGI) is then able to market the upper segment of Sumas to Stanfield to other customers.

Capacity release has also resulted in a bundled service called citygate, in which gas marketers bundle gas supplies with available capacity to be delivered directly to a market's gate stations. This grants additional flexibility to customers attempting to procure gas supplies for a specified period (i.e. during a peak or winter period) by allowing the customer to avoid contracting for year-round capacity which would not be used during off-peak periods.

Pursuant to the requirements under the Services Agreement between Intermountain and IGI, IGI is obligated to generate the maximum cost mitigation possible on any unutilized firm transportation capacity Intermountain has throughout the year. In performing this obligation, IGI must also insure that: 1) in no way will there be any degradation of firm service to Intermountain's residential and commercial customers, and 2) that Intermountain always has first call rights on any of its firm transportation capacity throughout the year.

With the introduction of natural gas deregulation under FERC Order 436 in 1985 and the subsequent FERC Orders 636, 712, 712A and 712B, the rules and regulations around capacity release transactions for interstate pipeline capacity were developed. These rules cover such activity as: 1) shipper must have title; 2) prohibition against tying arrangements and 3) illegal buy/sell transactions. These rules and regulations are very strict and must always be adhered to or the shipper is subject to significant fines (up to $1 million per day per violation) if ever violated.

The FERC jurisdiction interstate pipelines for which Intermountain holds capacity are NWP and GTN. To facilitate capacity release transactions, all pipelines have developed an Electronic

Bulletin Board (EBB) for which such transactions are to be posted. All released transportation capacity must be posted to the applicable pipeline EBB and in a manner that allows a competing party to bid on it.

Capacity Release Process

Over the past 10 to 15 years, IGI, because of its significant market presence in the Pacific Northwest, has been able to generate several millions of dollars per year in released capacity mitigation dollars on behalf of Intermountain for pass-back to its customers and to reduce the cost of unutilized firm transportation capacity rights. In this effort, IGI can determine what the appetite is in the competitive marketplace for firm transportation releases on NWP and GTN. It does this via direct communication with third parties or by market intelligence it receives from its marketing team as it deals with its customers throughout the region. However, the most effective way is using the EBB. IGI performs its obligation to Intermountain in one of two ways. First, if IGI itself is interested in utilizing any of Intermountain's unutilized firm transportation capacity, it determines what it believes is a market competitive offer for such and that is then posted to the EBB as a pre-arranged deal. As a pre-arranged deal, the transaction remains on the EBB for the requisite time and any third party has the opportunity to offer a higher bid. If this is done, then IGI can chose to match the higher bid and retain the use of the capacity, or not to match and the capacity will be awarded to the higher third-party bidder.

Second, if IGI is not interested in securing any unutilized capacity then it will post such capacity to the EBB as available and subject to open bidding by any third party. As such, the unutilized capacity will be awarded to the highest bidder. It should be noted that IGI posts to the EBB, as available capacity, certain volumes of capacity for certain periods every month during bid week. This affords the most exposure to parties which may be interested in securing certain capacity rights. However, to date, third parties have chosen to bid on such available capacity only a handful of times over all these years.

It should also be noted, that to protect the availability of firm transportation to Intermountain's residential and commercial customers during the year, all released capacity postings to the EBB, whether pre-arranged or not, are posted as recallable capacity. This means that Intermountain can recall the capacity at any time, if necessary, to cover its customer demand.

Non-Traditional Supply Resources

Non-traditional supply resources help supplement the traditional supply resources during peak demand conditions. Non-traditional supply resources consist of energy supplies not received from an interstate pipeline supplier, producer or interstate storage operator. Six non-traditional supply resources were considered in this IRP and are as follows:

1. Diesel/Fuel Oil
2. Coal
3. Wood Chips
4. Propane
5. Satellite/Portable LNG Facilities
6. Biogas Production

While a large volume industrial customer's load profile is relatively flat when compared to most residential and commercial customers, the Company's industrial customers are still a significant contributor to overall peak demand. However, some industrial customers have the ability to use alternate fuel sources to temporarily reduce their reliance on natural gas. By using alternative energy resources such as coal, propane, diesel and wood chips, an industrial customer can lower its natural gas requirement during peak load periods while continuing to receive the energy required for their specific process. Although these alternative resources and related equipment typically are available to operate any time during the year, most are ideally suited to run during peak demand from a supply resource perspective. However, only the industrial market has the capability to use any of the aforementioned alternate fuels in large enough volumes to make any material difference in system demand. More specifically, only industrial customers located along the Idaho Falls Lateral are able to use any of these non-traditional resources to offset firm demand throughout the Company's system. In order to rely on these types of peak supplies, Intermountain would need to engage in negotiations with specific customers to ensure availability. The overall expense of these kinds of arrangements is difficult to assess.

The remaining non-traditional resources, including satellite/portable LNG facilities and biogas production, are technically not a form of demand side management. However, satellite/portable LNG typically has the capability to provide additional natural gas supply at favorable locations within a potentially constrained distribution system. Satellite/portable LNG can therefore supplant the normal capacity upgrades performed on a distribution system by creating a new, portable supply point to maximize capacity possibilities. Biogas production could potentially supply a distribution system in a similar fashion, however, the location of a biogas facility, which is determined by the producer, may not align with a constrained location of the distribution system, thus limiting its potential efficacy as a non-traditional supply resource.

Diesel/Fuel Oil

There are three large volume industrial customers along the IFL that currently have the potential to use diesel or fuel oil as a natural gas supplement. These customers are able to utilize onsite fuel storage tanks along with additional pipelines and equipment to switch their boilers over to burn oil and decrease a portion of their gas usage. Burning diesel or fuel oil in lieu of natural gas requires permitting from the local governing agencies, a process which can be lengthy depending on the specific type of fuel oil used, and also increases the level of emissions from the customer's plant.

Out of the three industrial customers that currently have equipment to burn fuel oil, only one customer has the ability to supplement its natural gas usage; the other two customers lack the ability to switch to diesel or fuel oil due to intentionally not renewing the requisite permits or choosing not to purchase and store fuel oil at their facility. The estimated capital cost to install a diesel storage system is approximately $200,000 - $500,000 depending on usage requirements and days of storage. The estimated cost of diesel or fuel oil is between $2.05 - $2.97 per gallon depending on fuel grade and classification, time of purchase and quantity of purchase. The conversion cost to natural gas is roughly $1.38 to $2.00 per therm.

Coal

Coal use is very limited as a non-traditional supply resource for firm industrial customers within Intermountain's service territory. In order to use coal to offset natural gas demand, an industrial customer must maintain a separate boiler dedicated to coal in addition to its natural gas boiler. The customer must also have additional equipment installed at its facility to transport the coal to the boiler. Regulations and permitting requirements can also be a challenge. Only three firm industrial customers remain on Intermountain's system that have the ability and requisite permitting to offset natural gas demand with coal.

The cost of coal in the Northwest is approximately $50 per ton, including transportation and depending on the quality of the coal. Lower BTU coal would range from 8,000 – 13,000 BTU per pound while higher quality coal would range from 12,000 - 15,000 BTU per pound. This translates into a per therm cost of coal of roughly $0.21, plus permitting and equipment operation and maintenance costs.

Wood Chips

Using wood chips as alternative fuel is a practice utilized by one large volume industrial customer on the IFL. In order to accommodate wood burning there must be additional equipment installed, such as wood fired boilers, wood chip transport and dry storage facilities. The wood is supplied from various tree clearing and wood mill operations that produce chips within regulatory specifications to be used as fuel. The chips are then transported by truck to the location where the customer will typically utilize them as a fuel source for a few months each year. The wood fired boilers of this industrial customer are currently operated in conjunction with natural gas boilers, and technically would not offset natural gas usage. For comparison purposes, the wood fired boilers, if used to replace natural gas for this specific industrial customer, could offset gas usage by approximately 7,500 therms per day. Unfortunately, this single customer does not have the ability to utilize any more wood fuel than it is currently using.

The cost of wood continually changes based on transportation, availability, location and the type of wood processing plant that is providing the chips. Wood has a typical energy value of 5,000-6,000 BTU's per pound, which converts into 16-20 pounds of wood being burned to produce one therm of natural gas.

Propane

Since propane is similar to natural gas, the conversion to propane is much easier than a conversion to most other non-traditional supply resources. With the equipment, orifices and burners being similar to that of natural gas, an entire industrial customer load (boiler and direct fire) may be switched to propane. Therefore, utilizing propane on peak demand could reduce an industrial customer's natural gas needs by 100%. The use of propane requires onsite storage, additional gas piping and a reliable supply of propane to maintain adequate storage. Currently there are no industrial customers on the Company's system that have the ability to use propane as a feasible alternative to natural gas.

Capital costs for propane facilities can become relatively high due to storage requirements. Typical capital costs for a peak day send out of 30,000 therms per day, and the storage tanks required to sustain this load, are approximately $600,000 - $700,000. Storage facilities should be designed to accommodate a peak day delivery load for approximately seven days. The average cost of propane is roughly $2.50 per gallon, which is a natural gas equivalent to $2.69 per therm. [NOTE: One gallon of propane is approximately 91,600 BTU]. Fixed operation and maintenance costs are approximately $50,000 - $100,000 per year.

Biogas Production

Biogas can be defined as utilizing any biomass material to produce a renewable fuel gas. Biomass is any biodegradable organic material that can be derived from plants, animals, animal byproduct, wastewater, food/production byproduct and municipal solid waste. After processing of biogas to industry purity standards the gas can then be used as a renewable supplement to traditional natural gas within Company facilities.

Idaho is one of the nation's largest dairy producing states which make it a prime location for biogas production utilizing the abundant supply of animal and farm byproducts. Southern Idaho currently has multiple interested parties reviewing the prospect of constructing an anaerobic digester facility and becoming a gas supplier on Intermountain's distribution system. At this time, there is one biogas production facility contracted to begin supplying renewable natural gas in 2019. Intermountain is also in communication with other potential producers within the service territory.

Satellite/Portable LNG Equipment

Satellite/portable LNG equipment allows natural gas to be transported in tanker trucks in a cooled liquid form thus allowing larger BTU quantities to be delivered to key supply locations throughout the distribution system. Liquefied natural gas has a tremendous withdrawal capability because the natural gas is in a denser state of matter. Portable equipment has the ability to boil LNG back to a gaseous form and deliver it into the distribution system by heating the liquid from -260 degrees Fahrenheit to a typical temperature of 50 – 70 degrees Fahrenheit. This portable equipment is available to lease or purchase from various companies and can be used for peak shaving at industrial plants or within a distribution system. Regulatory and environmental approvals are minimal compared to permanent LNG production plants and are dependent upon the specific location where the portable LNG equipment is to be placed. The available delivery pressure from LNG equipment ranges from 150 psig to 650 psig with a typical flow capability of approximately 2,000 - 8,000 therms per hour.

Intermountain Gas currently operates a portable LNG unit on the northern end of the Idaho Falls Lateral to assist in peak shaving the system. In addition to the portable equipment, Intermountain also has a permanent LNG facility on the IFL that is designed to accommodate the portable equipment, provide an onsite control building and allow onsite LNG storage. The ability to store LNG onsite allows Intermountain to partially mitigate the risk associated with relying on truck deliveries during critical flow periods. The LNG delivery risk is also reduced now that Intermountain has the ability to withdraw LNG from the Nampa LNG storage tank and can transport this LNG around the state in a timely manner. With Nampa LNG readily available, the cost and dependence of third-party supply is removed.

The cost of the portable LNG equipment is approximately $1 – $2.5 million with additional cost to either lease or purchase property to place the equipment and the cost of the optional permanent LNG facility. The fixed cost to lease the portable equipment is approximately $250,000 - $350,000 per month plus the cost of LNG.

Lost and Unaccounted For Natural Gas Monitoring

Intermountain Gas Company is pro-active in finding and eliminating sources of Lost and Unaccounted For (LAUF) natural gas. LAUF is the difference between volumes of natural gas delivered to Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers. Intermountain is consistently one of the best performing companies in the industry with a three-year average LAUF percentage of .1176% (see Figure 28 below).

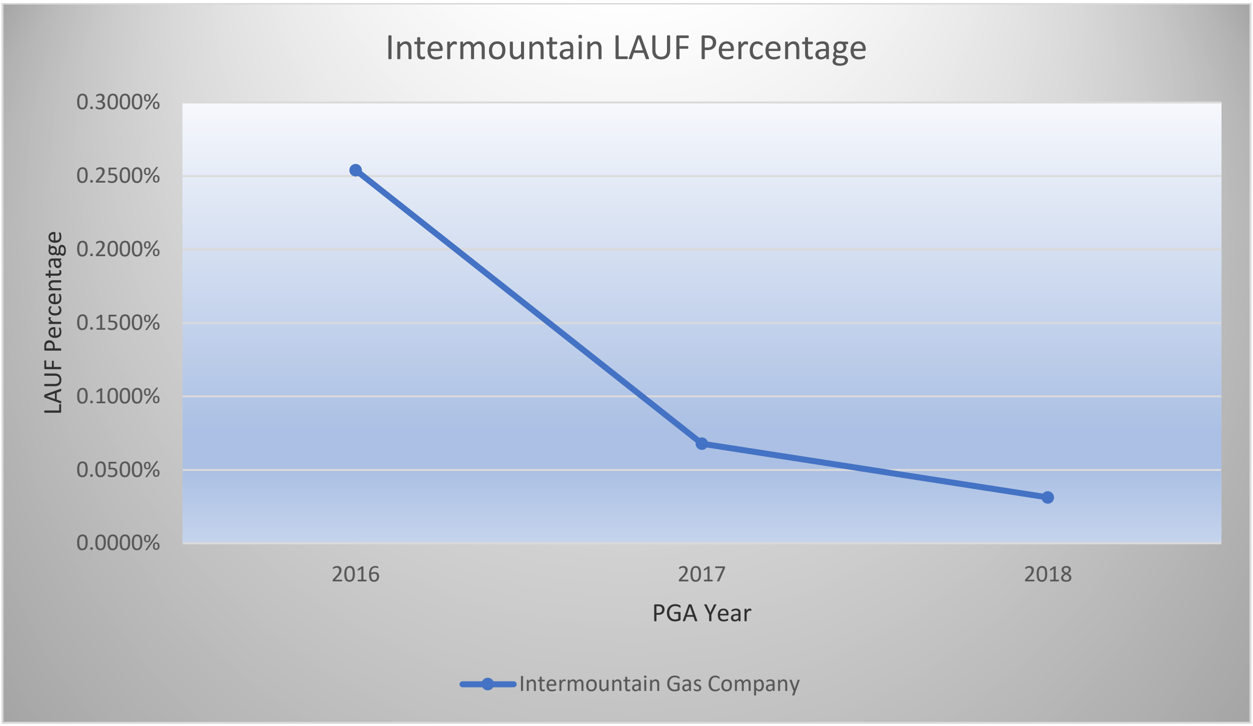


Figure 28: Intermountain LAUF Statistics

Intermountain utilizes a system to monitor and maintain a historically low amount of LAUF natural gas. This system is made up of the following combination of business practices:

- Perform ongoing billing and meter audits
- Routinely rotate and test meters for accuracy
- Conduct leak surveys on one-year and four-year cycles to find leaks on the system
- Natural gas line damage prevention and monitoring
- Implementing advanced metering infrastructure system to improve meter reading audit process
- Monitor ten weather location points to ensure the accuracy of temperature related billing factors

- Utilize hourly temperatures for a 24-hour period, averaged into a daily temperature average, ensuring accurate temperature averages for billing factors

Billing and Meter Audits

Intermountain conducts billing audits to identify low usage and zero usage with each billing cycle. Intermountain also works to ensure billing accuracy of newly installed meters. These audits are performed to ensure that the correct drive rate and billing pressure are programmed for the meter and billing system to avoid billing errors. Any corrections are made prior to the first bill going out.

Intermountain also compares on a daily and monthly basis its telemetered usage versus the metered usage that Northwest Pipeline records. These frequent comparisons enable Intermountain to find any material measurement variances between Intermountain's distribution system meters and Northwest Pipeline's meters.

Table 12: 2016 – 2018 Billing and Meter Audit Results

Billing and Meter Audit Results			
	2016	2017	2018
Dead Meters	413	457	310
Drive Rate Errors	9	12	4
Pressure Errors	30	7	24
Totals	452	476	338

Meter Rotation and Testing

Meter rotations are also an important tool in keeping LAUF levels low. Intermountain regularly tests samples of its meters for accuracy. Sampled meters are pulled from the field and brought to the meter shop for testing. The results of tests are evaluated by meter family to determine the pass/fail of a family based on sampling procedure allowable defects. If the sample audit determines that the accuracy of certain batches of purchased meters are in question, additional targeted samples are pulled and any necessary follow up remedial measures are taken.

In addition to these regular meter audits, Intermountain also identifies the potential for incorrectly sized and/or type of meter in use by our larger industrial customers. IGC conducts a monthly comparison to the billed volumes as determined by the customer's meter. If a discrepancy exists between the two measured volumes, remedial action is taken.

Leak Survey

On a regular and programmed basis, Intermountain technicians check Intermountain's entire distribution system for natural gas leaks using sophisticated equipment that can detect even the smallest leak. The surveys are done on a one-year cycle in business districts and a four-year cycle in other areas. This is more frequent than the legal requirement, which mandates leak surveys on one-year and five-year cycles. When such leaks are identified, which is very infrequent, remedial action is immediately taken. Intermountain will repair found leaks typically within 60 days, which is more aggressive than the industry where lower grade leaks are often monitored for safety and not repaired immediately.

Damage Prevention and Monitoring

Unfortunately, human error leads to unintentional excavation damage to our distribution system. When such a gas loss situation occurs, an estimate is made of the escaped gas and that gas then becomes “found gas” and not “lost gas”. To help eliminate instances of gas loss resulting from excavation damage, Intermountain is in the process of implementing a comprehensive damage prevention program to reduce the number of gas line damages.

Since the 2017 IRP was filed, Intermountain has added a full-time person to create and manage the Company’s damage prevention program. The program focuses on education to both business and agencies that interact with Intermountain and the public. Industry education and awareness has centered around trainings with contractors, excavators and first responders. In 2018, 18 different trainings were held across Intermountain’s service territory.

Intermountain also helped sponsor the development of a “Safe Excavator” app for iPhone and Android phones. This app provides quick access to vital information regarding Digline, or 811, processes and procedures. The app allows a contractor or excavator to request a locate ticket and also shows all the applicable rules and laws.

To educate the general public on the importance of calling 811 prior to any type of digging, Intermountain has participated in a variety of informational activities. The Company sponsored and staffed booths at events such as Buy Idaho, the Pocatello Environmental Fair, the Associated General Contractors golf tournament, and the Boise Hawks baseball games. Intermountain placed ads in Chamber of Commerce publications, the Associated General Contractors directory and city business directories. The Company also ran over 20,000 radio and TV spots in the Boise, Idaho Falls, and Twin Falls markets promoting the need to call 811 before digging.

The additional focus on education and awareness is having an impact. Intermountain has seen a decrease in incidents that damage facilities, and especially a decrease in incidents that cause gas loss. There is still work to do, however. There continues to be instances where the contractor or individual either does not call 811 before digging or calls but does not pay attention to the marking of the utility facilities. Continued focus on damage prevention by Intermountain as well as the support of the newly created Idaho Damage Prevention Board should help to further reduce the incidences of excavation damage and related gas loss in the future.

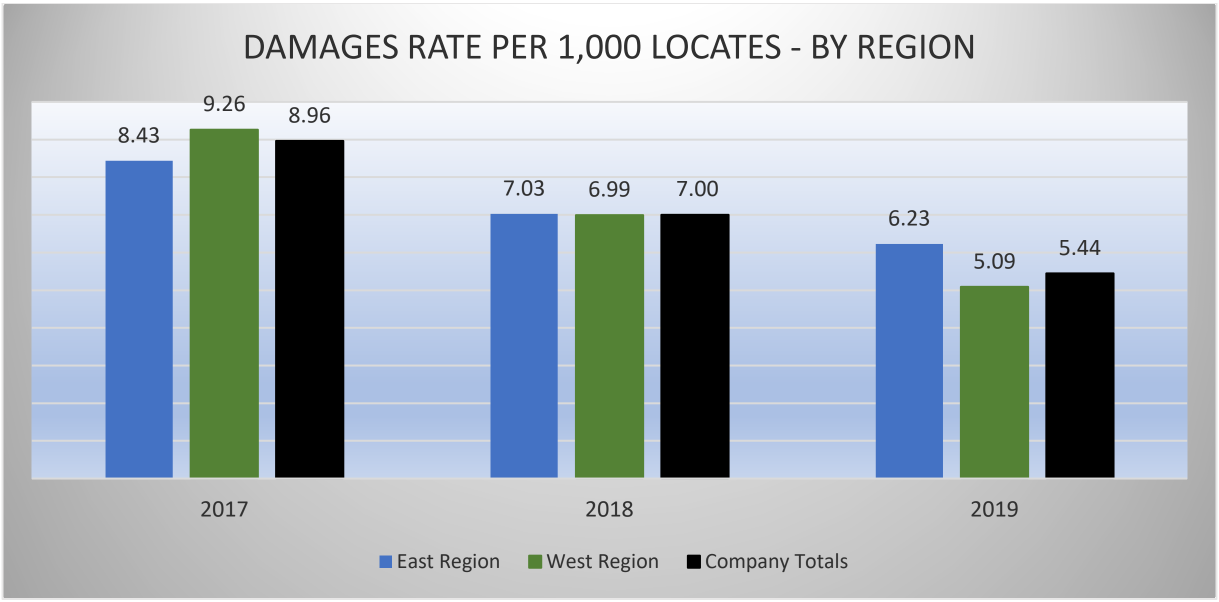


Figure 29: Intermountain Damages Rate Per 1,000 Locates – By Region

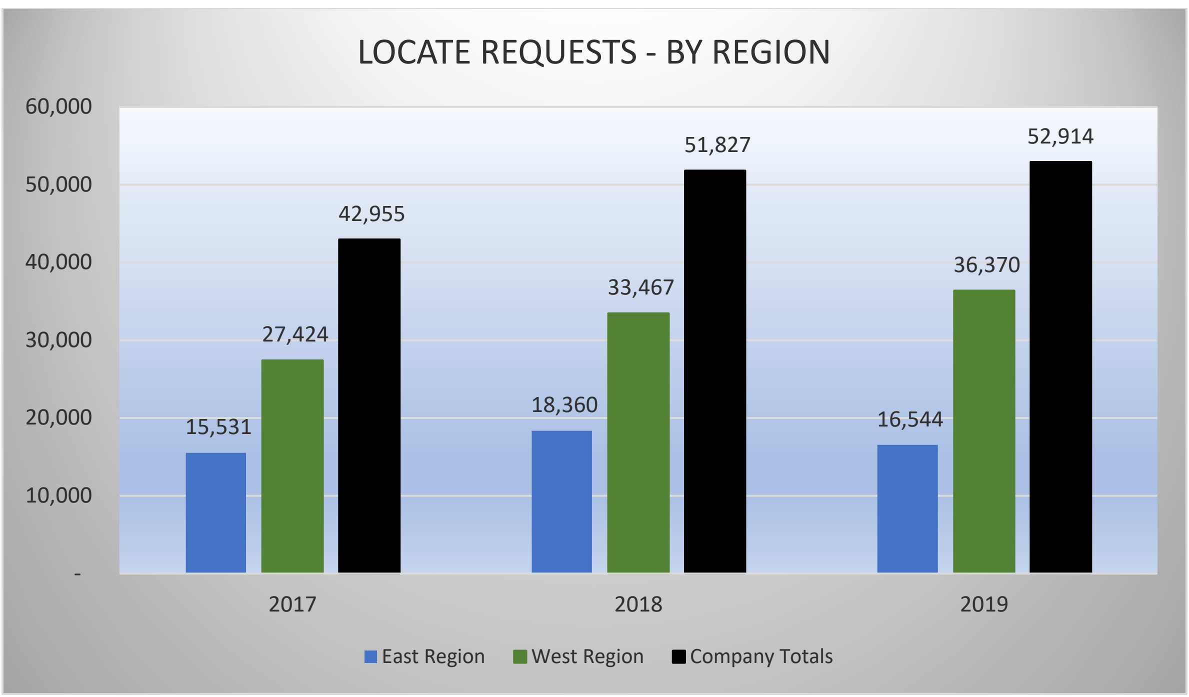


Figure 30: Intermountain Locate Requests – By Region

The figures above show the damage rate per 1,000 locates, and total locates for 2017 through 2019. The Figure 31 on the next page shows total damages by region and year for 2017 through 2019.

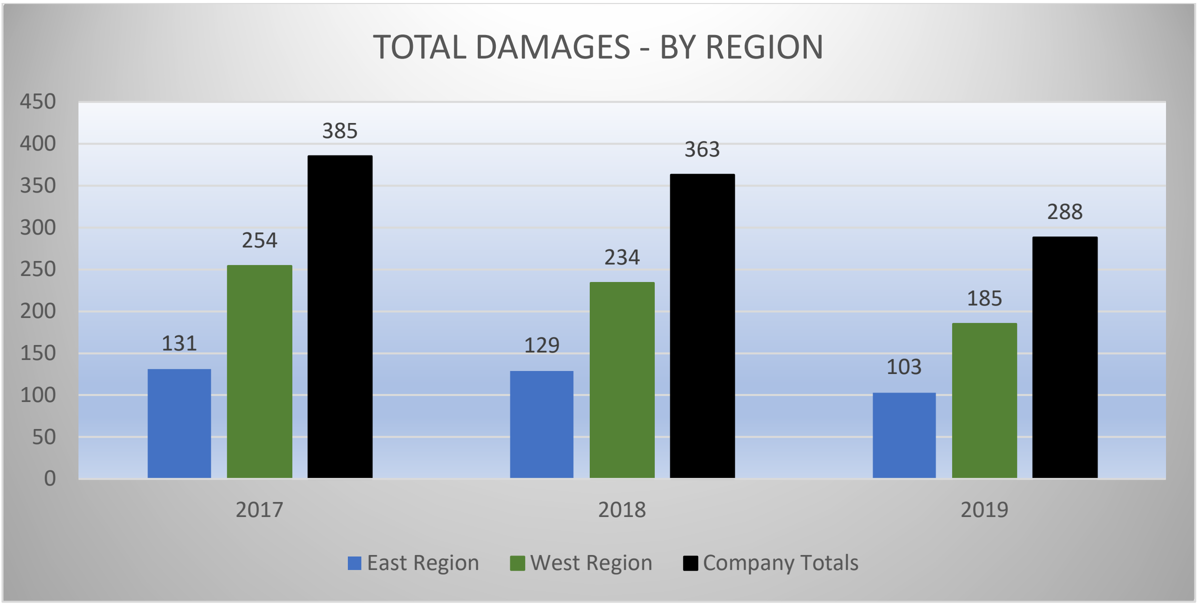


Figure 31: Intermountain Total Damages – By Region – Company

Advanced Metering Infrastructure

Intermountain is 50% complete with implementing Itron's fixed-network metering infrastructure, with a plan to complete the project by the end of 2020. This system utilizes a fixed mounted data collector using two-way communication to endpoints and to the repeater to collect on-demand reads and issue network commands. This system provides a robust collection of time-synchronized interval data, and when coupled with a meter data management system, it helps Intermountain:

- Improve customer service
- Refine forecasted consumption
- Manage and control tampering and theft
- Synchronize endpoint clocks to ensure data collected territory-wide is accurately time-stamped
- Retrieve missing interval data in the event of an outage
- Streamline the process to identify billing errors

Weather and Temperature Monitoring

Intermountain increased the number of weather monitoring stations in the early 2000's, from five to ten weather location points, to ensure the accuracy of temperature related billing factors. Additionally, Intermountain utilizes hourly temperatures for a 24-hour period, averaged into a daily temperature average, ensuring accurate temperature averages for billing factors. The weather and temperature monitoring provide for a better temperature component of the billing factor used to calculate customer energy consumption.

Summary

Intermountain continues to monitor LAUF levels and continuously improves business processes to ensure the company maintains a LAUF rate among the lowest in the natural gas distribution industry.

Core Market Energy Efficiency

As the cleanest, safest most affordable energy source available, why would we want consumers to use less natural gas? The wise use of our resources through high efficiency appliances and home construction helps individual customers save on their energy usage and monthly bill. The wise use of the commodity itself, and efficient use of the Intermountain Gas distribution system as a whole, benefits all of the Company's customers. Efficient use delays the need for expensive system upgrades while still allowing Intermountain to provide safe, reliable, affordable service to all customers.

From a corporate perspective, "At MDU Resources, we believe we have a responsibility to use natural resources efficiently and minimize the environmental impact of our activities." This is the Environmental Policy adopted by the Company on August 1, 1991, restated in 1998 and August 17, 2017. As a Company, our environmental goals are:

- To minimize waste and maximize resources
- To be a good steward of the environment while providing high quality and reasonably priced products and services; and
- To comply with or surpass all applicable environmental laws, regulations and permit requirements.

Market Transformation

The Gas Technology Institute (GTI) is our nation's leader in ongoing natural gas research, as well as the deployment and commercialization of new natural gas efficiency technologies. The goal of GTI is to solve important energy challenges while creating value in the marketplace. As part of this effort, GTI continues to perform important ongoing research and development work in the natural gas equipment arena through their Utilization Technology Development (UTD) group.

UTD is comprised of 20 member companies that serve more than 47 million natural gas customers in the Americas and Europe. UTD creates and advances products, systems, and technologies to save consumers money, save energy, integrate renewable energy with natural gas, and achieve safe, reliable, resilient end-user operation with superior environmental performance.

GTI uses funds contributed by member companies to leverage matching grants to make research dollars go further. Although not all research efforts are successful, Intermountain has participated in a number of projects that have reached the point of commercial viability. A sample of those projects includes:

Gas-fired Absorption Heat Pump (GAHP) for Space Heating or Commercial Water Heating

The GAHP can be used for space or water heating applications and is undergoing a four-unit field test in Wisconsin and Tennessee with prospective UTD manufacturing partner Trane and support from the U.S. Department of Energy, UTD and others. The GAHP has field-demonstrated an Annual Fuel Utilization Efficiency (AFUE) of 140%, with 45% gas savings, an estimated financial payback period of as low as three years, and ultra-low NOx emissions. The GAHP demonstrated continued operation under extreme cold weather conditions in Wisconsin during the January-February 2019 Polar Vortex.

Low NOx Advanced 3D-Printed Nozzle Burner

A novel design for next-generation retention nozzles leverages new additive manufacturing capabilities and equipment. In 2019, UTD is evaluating technology licensing applications in boilers and air heating. Laboratory tests to date have demonstrated an efficiency increase of 3-6% and a 50%-75% reduction in NOx emissions compared to current burners.

On-Demand Heat and Power System

This technology captures and stores renewable energy (or other resources, including waste heat), augments it with natural gas as needed, and delivers heat and power on-demand to commercial, industrial, and other users. In 2019, the technology is moving to a pilot field scale-up demonstration in California.

Self-Powered Tankless Water Heater

Tankless water heaters yield higher levels of efficiency than storage-type water heaters but require the added expense of an electrical connection and are susceptible to power outages unless a separate battery back-up system is installed. UTD researchers have assessed leading thermoelectric generator (TEG) technologies and, in 2019, are analyzing opportunities to economically integrate TEG and other technologies into a prototype water heater design.

High Efficiency Commercial Clothes Dryer

An advanced natural gas fired commercial clothes dryer is being created and demonstrated at laboratory scale that has the potential to save at least 50% of the energy used in the commercial clothes drying sector. It is being developed in partnership with Oak Ridge National Laboratory and others, with financial support from the U.S. Department of Energy and UTD.

This kind of research and development contributes to continued, market-transforming energy efficiency in the natural gas industry. Intermountain believes all customers benefit from investments in improving the efficiency of natural gas applications and technology improvements that reduce emissions.

Residential Energy Efficiency Program

The goal of Intermountain's Energy Efficiency program is to acquire cost-effective demand side resources. Unlike supply side resources, which are purchased directly from a supplier, demand side resources are purchased from individual customers in the form of unused energy as a result of energy efficiency. The demand side resources acquired through the Company's EE Program (also referred to as Demand Side Management or DSM) ultimately allow Intermountain to displace the need to purchase additional gas supplies, delay contracting for incremental pipeline capacity, and possibly negate or delay the need for reinforcement on the Company's distribution system. The Company strives to raise awareness about home energy efficiency and inspire customers to reduce their individual demand for gas through outreach and education.

Collections for funding the EE program began on October 1, 2017. Active promotion and staffing of the EE program launched in January 2018. During the 2017-2021 IRP, DSM therm savings were projected for the first five years of the program, as illustrated in the following chart (Figure 32).

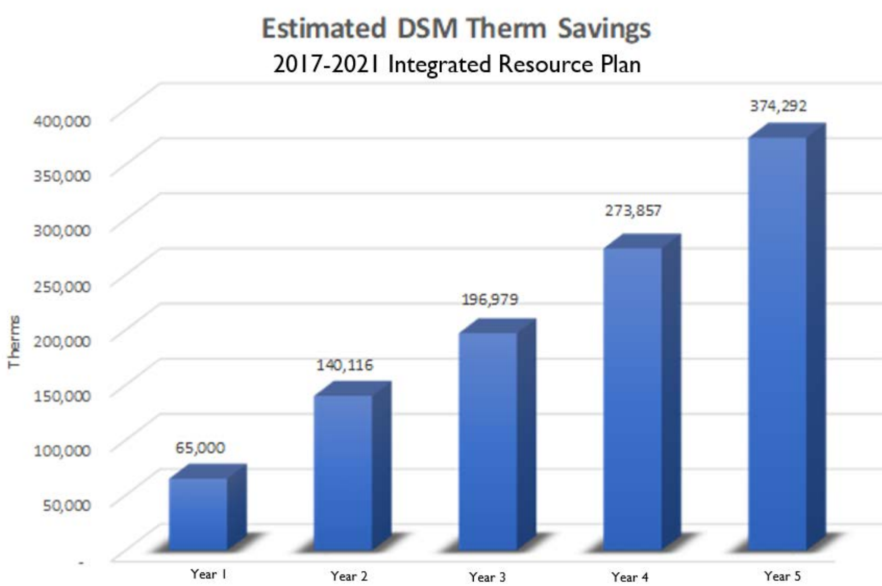


Figure 32: Estimated DSM Therm Savings

The initial program was intentionally designed to be a modest offering to allow for proper ramp up and promotion of the new program. The EE Program focused on two major rebate categories: appliance rebates for high-efficient natural gas appliances, and residential high-performance new construction with energy efficient design. Figures 33 and 34 are program brochures provided to customers though bill inserts in March 2018 and October 2018.

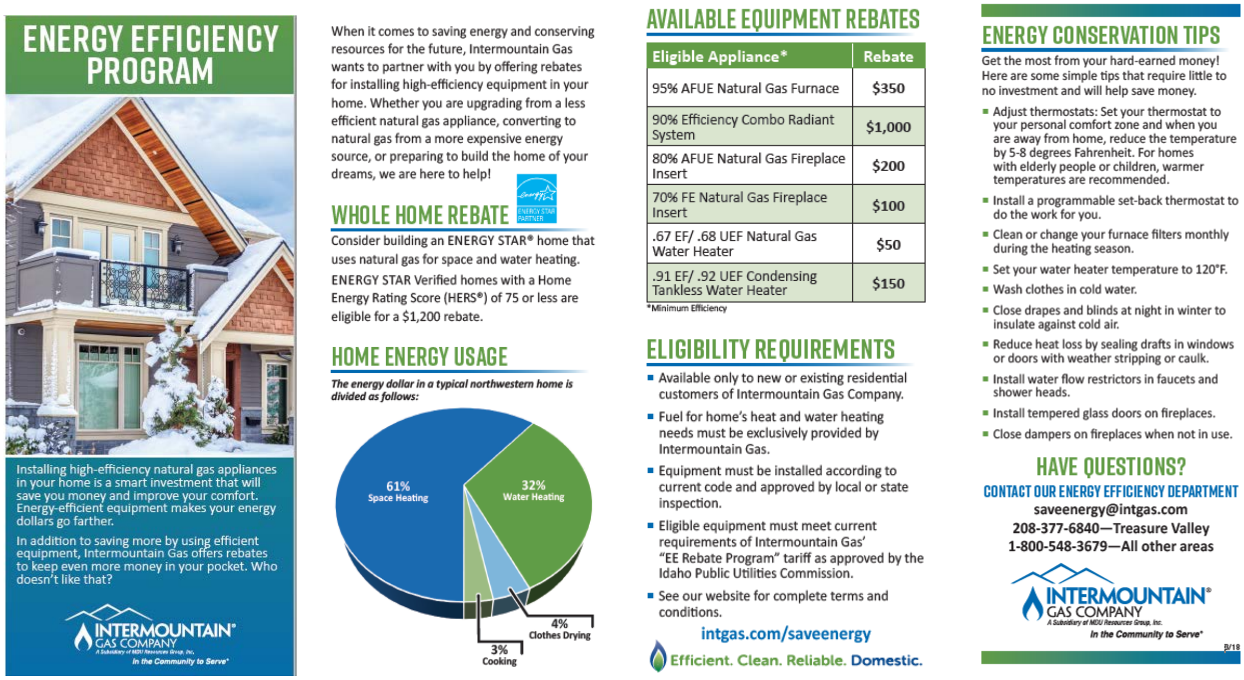


Figure 33: Energy Efficiency Program Brochure – March 2018

Figure 34: 2018 Energy Efficiency Customer Bill Insert – October 2018

Intermountain has assembled a Stakeholder group to provide input on the EE Program. The group met in November of 2018 and again in May of 2019. These meetings provide an opportunity for Intermountain to receive feedback on the current program's design and delivery. It also serves as a forum to discuss future program plans.

The EE Program is currently half-way through Program Year 2, and has invested in a more robust analysis of DSM resources for future program planning, including a modeling process by which DSM measures are selected based on cost-effectiveness, an explanation and update of avoided costs, and an explanation of the impact of DSM on supply and capacity needs.

Conservation Potential Assessment

In order to conduct a more robust analysis of all cost-effective DSM measures, Intermountain contracted with a third party to perform a Conservation Potential Assessment (CPA). The CPA is intended to support both short-term energy efficiency planning and long-term resource planning activities.

As outlined in the CPA report, the intent of the CPA is that it be used for:

- **Resource planning**: evaluate the impact of energy efficiency, fuel switching and codes and standards on long-term energy consumption and demand needs
- **Identify opportunities**: assess achievable DSM opportunities to improve DSM program planning and help meet long-term savings objectives, and determine which sectors, end-uses and measures hold the most potential
- **Efficiency program planning**: inform portfolio and program design considering funding level, market readiness and other constraints

In April of 2018, IGC sent a Request for Proposal (RFP) to 30 companies to conduct a CPA. After receiving six proposals, and interviewing three companies, Dunsky Energy Consulting (Dunsky) was retained to perform the assessment. Dunsky utilized the expertise of GTI, the leading natural gas energy and environmental research, development and training organization, as the primary research lead for the study. The scope of the study included conservation potential for both the residential and commercial sectors, over the 2020-2039 time period.

The purpose of the potential assessment was "to provide a realistic, high-level, assessment of the long-term energy efficiency potential that is technically feasible, cost-effective, and achievable through efficiency programs." Three categories of potential savings, depicted in Figure 35, were examined by applying economic considerations such as market barriers and cost tests. The Utility Cost Test (UCT) was applied to the theoretical maximum savings opportunity, or the technical savings category, to screen for only the cost-effective measures, resulting in the economic savings potential. The economic savings potential of cost-effective measures was further screened by applying market barriers to establish the achievable energy efficiency potential. To study the impacts on achievable potential savings, three different scenarios were tested: the low case, the base case and the max case.

Technical: Theoretical maximum savings opportunity, ignoring constraints such as cost-effectiveness and market barriers.

Economic: Applies economic considerations to technical potential, leaving only measures that are cost-effective. Screened on the Utility Cost Test (UCT).

Achievable: Applies market barriers to economic potential, resulting in an estimate of savings that can be achieved through efficiency program. Different scenarios are tested to examine their impacts on savings.

Figure 35: Categories of Potential Savings

Details of the three scenarios and the key insights to be examined with each scenario were as such:

- Low Case -applies low incentive levels, (35% of incremental measure costs), but with no budget constraints and over a broad set of cost-effective measures

  Key insight: *What level of saving can be achieved with a comprehensive offer, with incentives that are in the lower range?*

- Base Case – incentives increased to 50%, barrier reduction in Program Year 6, unconstrained budget – standard program approach

  Key insight: *How much more savings can be expected with increased incentive levels?*

- Maximum Case – incentive levels at 65%, barrier-reducing program delivery, unconstrained budget and measures

  Key Insight: *How would improved program delivery increase savings (e.g. consumer education, contractor training and support, etc.)*

The following chart (Figure 36) illustrates the cumulative technical, economic and achievable energy savings potential for the 2020-2039 period. The low, base, and max scenarios for achievable potential savings is also shown.

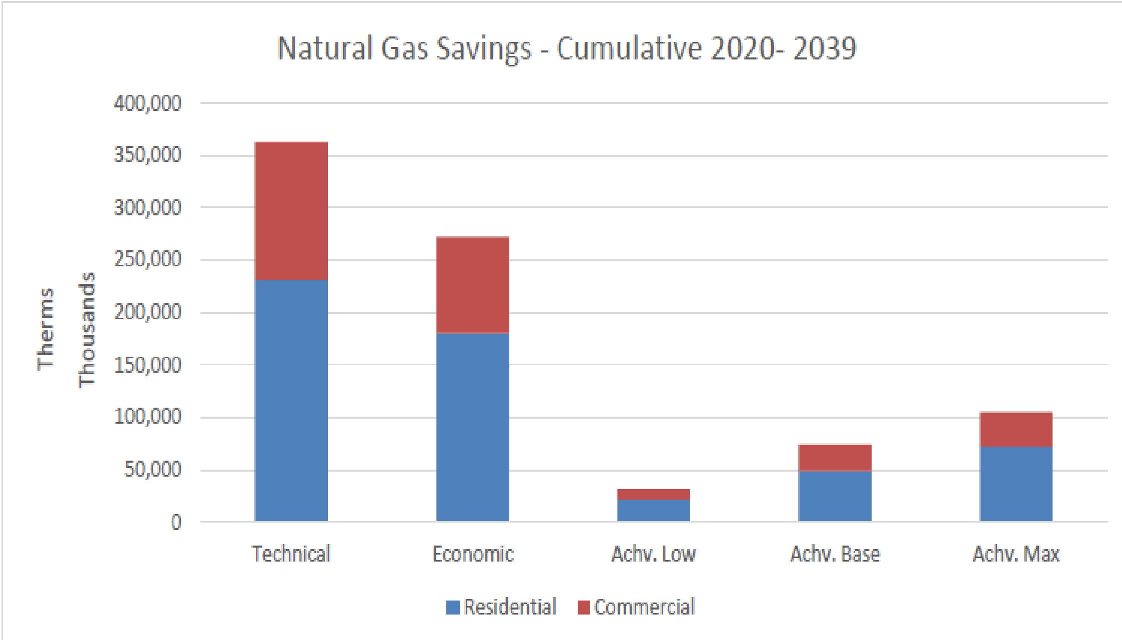


Figure 36: Natural Gas Savings – Cumulative 2020 - 2039

Base Scenario cumulative savings are illustrated in Figure 37, with attention on the first five-year period utilized in the IRP load forecast.

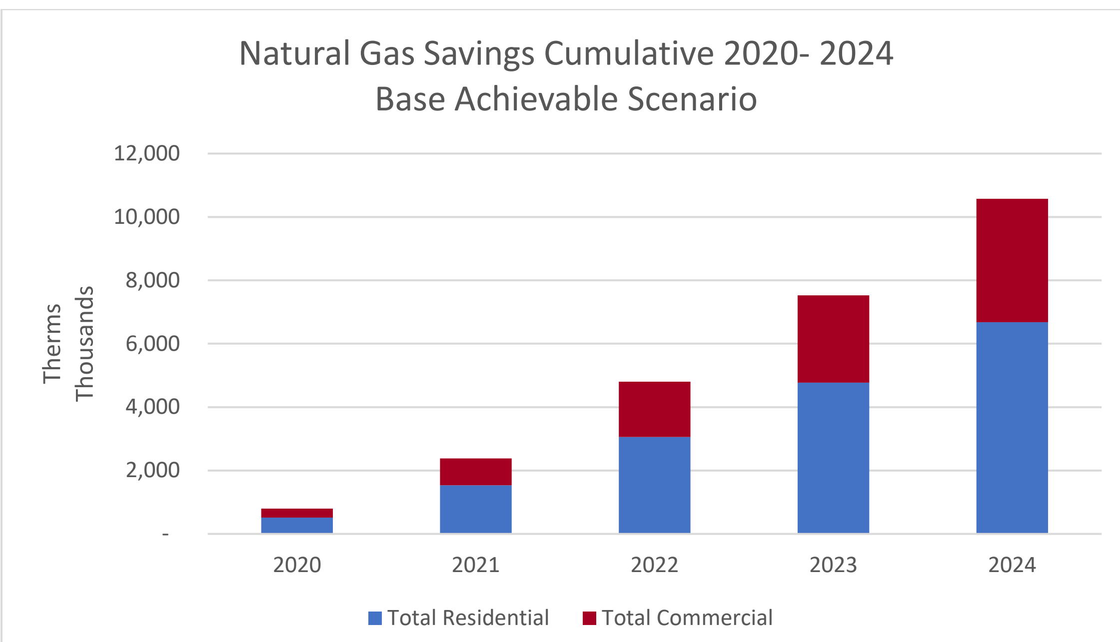


Figure 37: Natural Gas Savings Cumulative 2020 – 2024, Base Achievable Scenario

The base case scenario of the achievable potential energy savings estimates 41% of savings will come from HVAC, 32% from building envelope measures, and 27% from hot water measures for the residential sector during 2020-2024 program years. Likewise, the commercial sector is estimated to contribute 78% of potential energy savings from HVAC, 12% from kitchen measures, 8% from hot water, and 2% from various other commercial applications for the same time period.

For the 2020-2024 program years, the portfolio is projected to be cost-effective based on both the Utility Cost Test and the Total Resource Cost Test, see Table 13 below.

Table 13: Intermountain Portfolio Cost-Effectiveness Under UCT and TRC Tests

Sector	UCT			TRC		
	Low	Base	Max	Low	Base	Max
Residential	1.78	1.74	1.46	1.33	1.36	1.31
Commercial	2.40	2.21	1.81	1.53	1.49	1.38
Total	**1.97**	**1.90**	**1.33**	**1.40**	**1.41**	**1.33**

Findings specific to the first-five years of the study will require significant consideration:

- Savings in the low and base scenarios exhibit strong growth in the first five years followed by modest growth in the subsequent years of the study. Rapid growth in the first time period is attributed to expansion of residential offerings and introduction of new initiatives in the commercial sector.
- Savings under the base scenario are 40% higher than the low scenario in the first five years. The base scenario budget is more than double the low scenario budget, as higher incentive levels increase the costs of all savings. Despite the higher average cost per therm of savings in the base scenario, under the UCT, all savings are cost-effective.
- Efficiency measures provide a stable flow of gas savings. Savings as a percent of forecasted volumes remain close: 0.5% for the low case and 1% for the base case scenario.
- Under the base scenario, budgets need to increase significantly. First, as customers participate in greater numbers, and then as participation further grows due to strategies to address market barriers and increase participation.

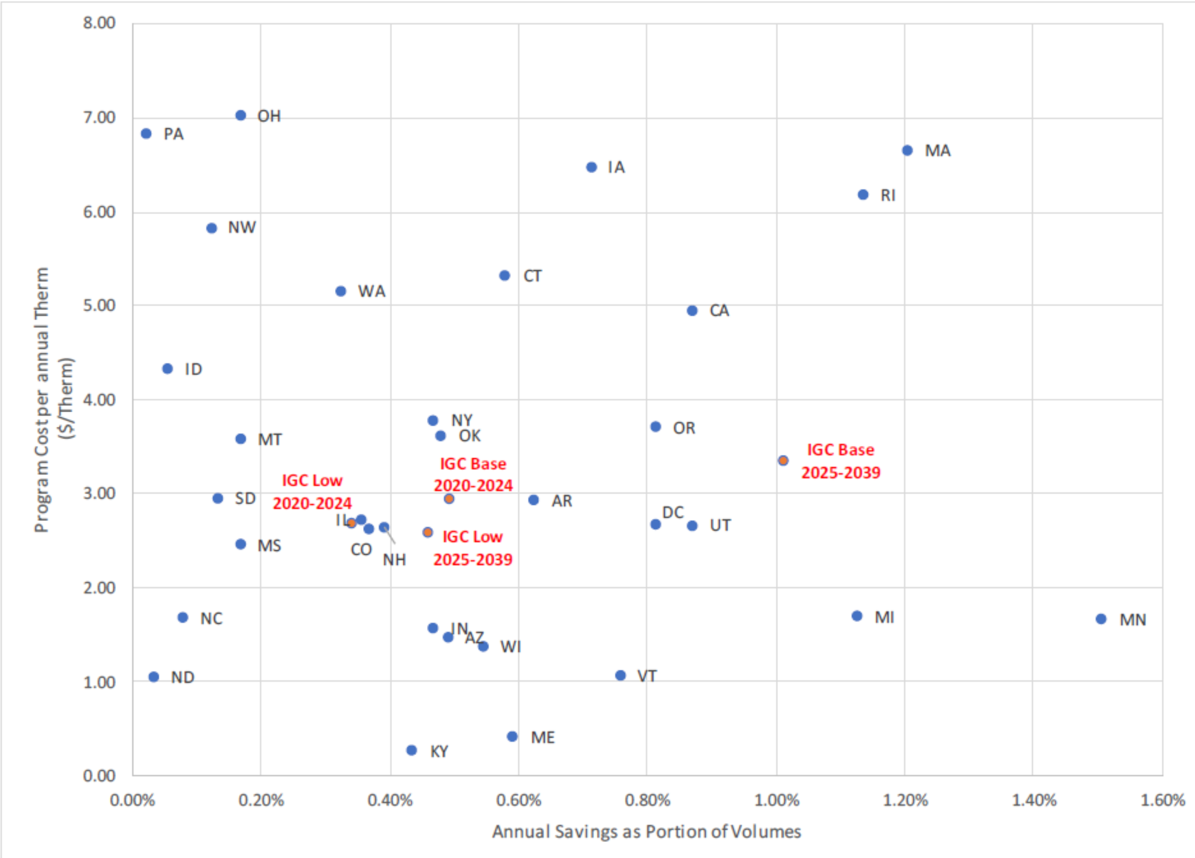


Figure 38: Intermountain's Portfolio Annual Savings Compared to Other Utilities

As seen in the chart above, a common metric to benchmark Intermountain's program against other jurisdictions is conducted by dividing the annual budget by first year savings. This metric does not consider the total savings for the complete measure lives and should not be compared with avoided costs, but it does still provide some key comparative insights. Low and base scenario savings and unit costs would place Intermountain among average utilities with savings ranging between 0.4 and 0.6%. With investments and sustained growth in the retrofit market, under the base scenario, Intermountain could evolve into one of the leading utilities, while maintaining costs at a reasonable level.

Savings potential from the base scenario were incorporated as a DSM resource in the Optimization model. Complete CPA results have been provided as Exhibit 4.

Large Volume Energy Efficiency

Through discussions with the customers and the information provided via the surveys, it is apparent that maximizing plant efficiency by optimizing production volumes while using the least amount of energy is a very high priority for the owners, operators, and managers of these large volume facilities. Nearly 20 years ago Intermountain developed an informational tool using SCADA and remote radio telemetry technology to gather, transmit and record the customer's hourly therm usage data. This data is saved on an internal server and provided to customers and their marketers/agents via a password protected website.

Usage data is useful in tracking and evaluating energy saving measures, new production procedures or new equipment. To deploy this tool, Intermountain installs SCADA units on customers' meters to records the meter volume each hour. That data is then transmitted via radio/telemetry communication technology to Intermountain's servers so it can be made available to customers.

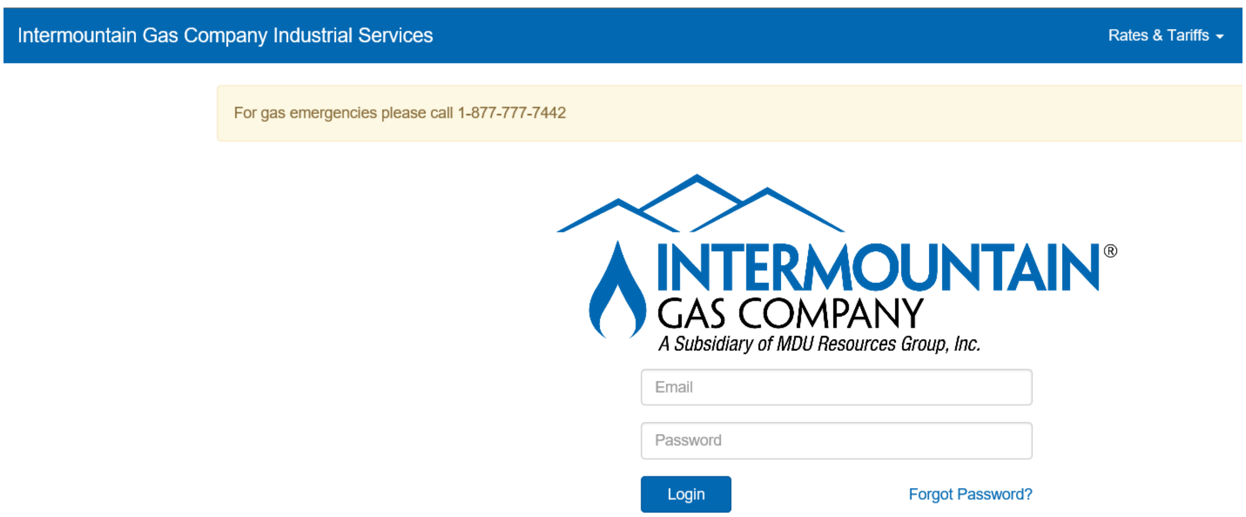


Figure 39: Large Volume Website Login

In order to provide customers access to this data, Intermountain has designed and hosts a Large Volume website, which is pictured in the figure above. The website is available on a 24/7 basis for Large Volume customers to log-in via the internet using a company specific username and customer managed password. After a successful log-in, the user immediately sees a chart showing the last 30 days of hourly usage for the applicable meter or meters, but also has the option to adjust the date range to see just a few hours or up to several years of usage data. An example of a month's worth of data is provided in the Figure 40. The user can also download the data in CSV format to review, evaluate, save and analyze natural gas consumption at their specific facility on an hourly, weekly, monthly, and annual basis as far back as 2015. Each customer may elect to have one or multiple employees access the site. Logins can also be created to make this same data available to a transport customer's natural gas marketer.

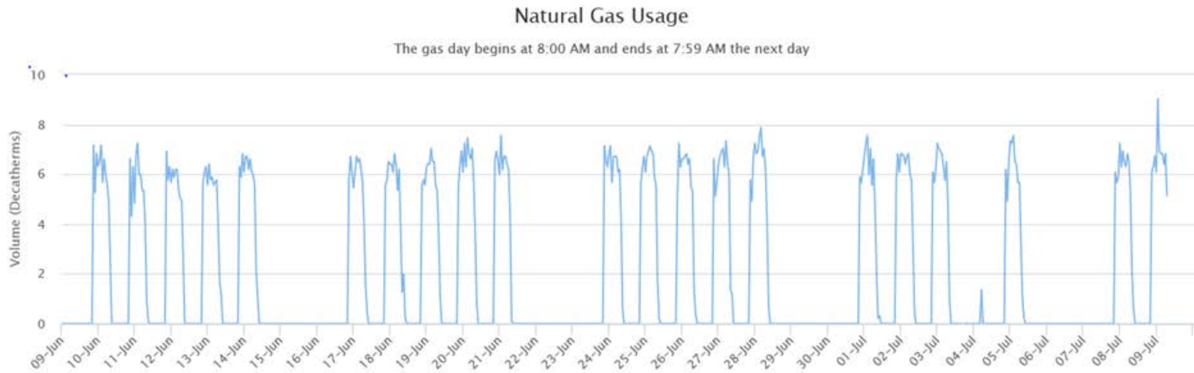


Figure 40: Natural Gas Usage History

The website also contains a great deal of additional information useful to the Large Volume customer. Customers can access information such as the different tariff services offered, answers to frequently asked questions and a potential marketer list for those interested in exploring transport service. The customer is also provided a "Contact Us" link and, in order to keep this site in the most usable format for the customer, a website feedback link is provided (see Figure 41). The site allows the Company to post information regarding things such as system maintenance, price changes, rate case information and anything else that might assist the customer or its marketer.

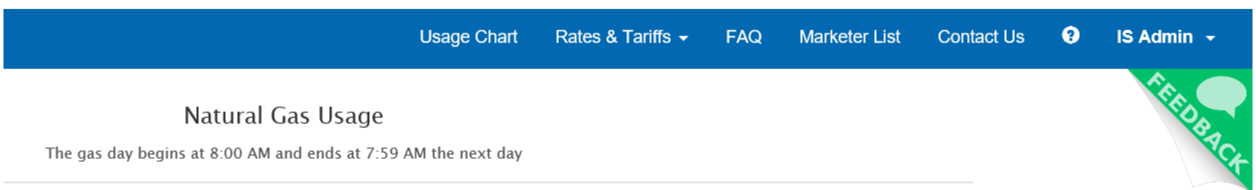


Figure 41: Feedback Link

Avoided Costs

Overview

The avoided cost is the estimated cost to serve the next unit of demand with a supply side resource option at a point in time. This incremental cost to serve represents the cost that could be avoided through energy conservation. The avoided cost forecast can be used as a guideline for comparing energy conservation with the cost of acquiring and transporting natural gas to meet demand.

This section presents IGC's avoided cost forecast and explains how it was derived. While the IRP is only a five-year plan, avoided costs are forecasted for 45 years to account for the full measure life of some conservation measures, such as ENERGY STAR certified homes, which have lives much longer than five years. The avoided cost forecast is based on the performance of IGC's portfolio under expected conditions.

Cost Incorporated

The components that go into Intermountain's avoided cost calculation are as follows:

$$AC_{nominal} = TCF + TCV + CC + DSC$$

Where:

- $AC_{nominal}$ = The nominal avoided cost for a given year.
- TCF = Fixed Transportation Costs
- TCV = Variable Transportation Costs
- CC = Commodity Costs
- DSC = Distribution System Costs

The following parameters are also used in the calculation of the avoided cost:

- The most recent forecast of commodity prices by gas hub utilized in the 2019 IRP.
- The inflation rate used is tied to the Consumer Price Index (CPI) and is 2.0%.
- The nominal discount rate of 6.68% is IGC's tax effected cost of capital.
- Northwest Pipeline rates are utilized since these are used for the majority of Intermountain's transport and are most transparent.
- Standard present value and levelized cost methodologies are utilized to develop a real and nominal levelized avoided cost by year.

Understanding Each Component

Fixed Transportation Costs

Fixed transportation costs are the cost per therm that Intermountain pays for the right to move gas along an interstate pipeline. As is implied by the name, this cost is incurred whether gas flows along a pipeline or not. This rate is set by the various pipelines and can be changed if the pipeline files a rate case. The final rates filed at the conclusion of a rate case (whether reached through settlement or hearing) must be approved by the Federal Energy Regulatory Commission (FERC). To model rate increases in its forecast, Intermountain multiplies its transportation costs by the CPI escalator. For its 2019 IRP, Intermountain assumes that contracts thru 2025 are already committed and so not avoidable. Starting in 2026, the unit cost of the NWP capacity inflated to nominal cost by the inflation rate is utilized.

Variable Transportation Costs

Variable transportation costs are the cost per therm that Intermountain pays only if the Company moves gas along a pipeline. This rate is set by the various pipelines and can be changed if the pipeline files a rate case. The final rates filed at the conclusion of a rate case (whether reached through settlement or hearing) must be approved by FERC. The current rates for NWP TF-1 variable costs are utilized and escalated by the inflation rate.

Commodity Costs

Commodity costs are the costs of acquiring one therm of gas. Since Intermountain does not know where it will purchase the next therm of gas, the max from all three basins from which Intermountain purchases gas is utilized (AECO, Sumas and Rockies). The price forecast went through 2036 and then an escalator was applied through the remainder of the forecast period.

Distribution System Costs

Distribution system costs capture the costs of bringing gas from the transportation pipeline's citygate to Intermountain's customers. For this IRP cycle, IGC calculates distribution system costs as its system weighted average of its authorized margins. These costs are inflated by the CPI escalator every year.

Optimization

Distribution System Modeling

A natural gas pipeline is constrained by the laws of fluid mechanics which dictate that a pressure differential must exist to move gas from a source to any other location on a system. Equal pressures throughout a closed pipeline system indicate that neither gas flow nor demand exist within that system. When gas is removed from some point on a pipeline system, typically during the operation of natural gas equipment, then the pressure in the system at that point becomes lower than the supply pressure in the system. This pressure differential causes gas to flow from the supply pressure to the point of gas removal in an attempt to equalize the pressure throughout the distribution system. The same principle keeps gas moving from interstate pipelines to Intermountain's distribution systems. It is important that engineers design a distribution system in which the beginning pressure sources, which could be from interstate pipelines, compressor stations or regulator stations, have adequately high pressure, and the transportation pipe specifications are designed appropriately to create a feasible and practical pressure differential when gas consumption occurs on the system. The goal is to maintain a system design where load demands do not exceed the system capacity, which is constrained by minimum pressure allowances at a determined point or points along the distribution system, and maximum flow velocities at which the gas is allowed to travel through the pipeline and related equipment.

Due to the nature of fluid mechanics there is a finite amount of natural gas that can flow through a pipe of a certain size and length within specified operating pressures. The laws of fluid mechanics are used to approximate this gas flow rate under these specific and ever-changing conditions. This process is known as "pipeline system modeling." Ultimately, gas flow dynamics on any given pipeline lateral and distribution system can be ascertained for any set of known gas demand data. The maximum system capacity is determined through the same methodology while calculating customer usage during a peak heating degree day.

In order to evaluate intricate pipeline structures a system model is created to assist Intermountain's engineering team in determining the flow capacity and dynamics of those pipeline structures. For example, before a large usage customer is incorporated into an existing distribution system, the engineer must evaluate the existing system and then determine whether or not there is adequate capacity to maintain that potential new customer along with the existing customers, or if a capacity enhancement is required to serve the new customer. Modeling is also important when planning new distribution systems. The correct diameter of pipe must be designed to meet the requirements of current customers and reasonably anticipated future customer growth.

Modeling Methodology

Intermountain utilizes a hydraulic gas network modeling and analysis software program called Synergi Gas, distributed and supported by DNV GL, to model all distribution systems and pipeline flow scenarios. The software program was chosen because it is reliable, versatile, continually improving and able to simultaneously analyze very large and diverse pipeline networks. Within the software program individual models have been created for each of Intermountain's various distribution systems including high pressure laterals, intermediate pressure systems, distribution system networks and large diameter service connections.

Each system's model is constructed as a group of nodes and facilities. Intermountain defines a node as a point where gas either enters or leaves the system, a beginning and/or ending location of pipe and/or non-pipe components, a change in pipe diameter or an interconnection with another pipe. A facility is defined in the system as a pipe, valve, regulator station, or compressor station; each with a user-defined set of specifications. The entire pipeline system is broken into three individual models for ease of use and to reduce the time requirements during a model run analysis. The largest model in use consists of approximately 71,000 active nodes, 580,000 graphic nodes and 75,600 facilities which are used along with additional model inputs to solve simultaneous equations through an iterative process, calculating pressures for over 70,000 unknown locations prior to analysis.

Synergi can analyze a pipeline system at a single point in time or the model can be specifically designed to simulate the flow of gas over a specified period of time, which more closely simulates real life operations which utilize gas stored in pipelines as line pack. While modeling over time an engineer can write operations that will input and/or manipulate the gas loads, time of gas usage, valve operation and compressor simulations within a model, and by incorporating the forecasted customer growth and usage provided within this IRP, Intermountain can determine the most likely points where future constraints may occur. Once these high priority areas are identified, research and model testing are conducted to determine the most practical and cost-effective methods of enhancing the constrained location. The feasibility, timeline, cost and increased capacity for each theoretical system enhancement is determined and then run through the IRP Optimization Model.

Potential Capacity Enhancements

Capacity enhancements within the Company's distribution system improve the ability to flow gas during periods of peak demand. Three capacity upgrades were considered in this IRP and are as follows:

1. Pipeline Loop
2. Pipeline Uprate
3. Compressor Station

The three capacity upgrades discussed below do not reduce demand nor do they create additional supply points, rather they increase the overall capacity of a pipeline system while utilizing the existing gate station supply points. When selecting capacity upgrades, a multitude of factors were considered including cost, maintenance and operation, growth, etc.

Pipeline Loop

Pipeline looping is a traditional method of increasing capacity within an existing distribution system. The loop refers to the construction of new pipe parallel to an existing pipeline that has, or may become, a constraint point. The feasibility of looping a pipeline is primarily dependent upon the location where the pipeline will be constructed. Installing gas pipelines through private easements, residential areas, existing asphalt, or steep and rocky terrain can greatly increase the cost to unjustifiable amounts when compared with alternative enhancement solutions.

The potential increase in system capacity by constructing a pipeline loop is dependent on the size and length of new pipe being installed, with typical increases in capacity ranging from 50,000 – 250,000 therms per day on large, high pressure laterals. The cost for a new pipeline installation of this magnitude is generally in the range of $7 - $20 million.

Pipeline Uprate

A quick and sometimes relatively inexpensive method of increasing capacity in an existing pipeline is to increase the maximum allowable operating pressure of the line, usually called a pipeline uprate. Uprates allow a company to maximize the potential of their existing systems before constructing additional facilities and are normally a low-cost option to increase capacity. However, leaks and damages are sometimes found or incurred during the uprate process creating costly repairs. There are also safety considerations and pipe regulations that restrict the feasibility of increasing the pressure in any pipeline, such as the material composition, strength rating and relative location of the existing pipeline.

Compressor Station

Compressor stations are typically installed on pipelines or laterals with significant gas flow and the ability to operate at higher pressures. Intermountain currently has two such transmission pipelines for which the installation of a compressor station could be practical: the Sun Valley Lateral and the Idaho Falls Lateral. Regulatory and environmental approvals to install a compressor station, along with engineering and construction time, can be a significant deterrent, but compressors can also be a cost effective, feasible solution to lateral constraint points. Compressor stations can be broken down into the following two scenarios:

A single, large-volume compressor can be installed on the pipeline when there is a constant, high flow of gas. The compressor is sized according to the natural gas flow and is placed in an optimal location along the lateral. This type of compressor will not function properly if the flow in the pipeline has a tendency to increase or decrease significantly. This type of station can have a price range of $3 - $6 million plus land, and typical operating and maintenance costs will range between $100,000 - $200,000 annually.

The second option is the installation of multiple, smaller compressors located in close proximity or strategically placed in different locations along a lateral. Multiple compressors are very beneficial as they allow for a large flow range, have some redundancy and use smaller and typically more reliable drivers and compressors. These smaller compressor stations are well suited for areas where gas demand is growing at a relatively slow and steady pace so that purchasing and installing these less expensive compressors can be done over time. This “just in time” approach allows a pipeline to serve growing customer demand for many years into the future while avoiding the more costly purchase of a single, larger station. However, high land prices or the unavailability of land may render this option economically or operationally infeasible. The cost of a smaller compressor station, excluding land, is estimated at $1.5 - $3 million with approximate operating and maintenance costs of $50,000 - $150,000 annually.

Load Demand Curves

The culmination of the demand forecasting process is aggregating the information discussed in the previous sections into a forecast of future load requirements. As the previous sections illustrate, the customer forecast, design weather, core market usage per customer data, and large volume usage forecast are all key drivers in the development of the load demand curves.

The IRP customer forecast provides a total Company daily projection through Planning Year (PY) 2023 and includes a forecast for each of the five AOIs of the distribution system. Each forecast was developed under each of three different customer growth scenarios: low growth, base case, and high growth.

The development of a design weather curve – which reflects the coldest anticipated weather patterns across the Company's service area – provides a means to distribute the core market's heat sensitive portion of Intermountain's load on a daily basis. Applying design weather to the residential and small commercial usage per customer forecast creates core market usage per customer under design weather conditions. That combined with the applicable customer forecast yields a daily core market load projection through PY23 for the entire Company, as well as for each AOI. Similar to the above, normal weather scenario modeling was also completed.

As discussed in the Large Volume Customer Forecast Section, the forecast also incorporates the large volume CD from both a Company-wide perspective (interstate capacity) as well as from an AOI perspective (distribution capacity). When added to the core market figures, the result is a grand total daily forecast for both gas supply and capacity requirements including a break-out by AOI.

Peak day sendout under each of these customer growth scenarios was measured against the currently available capacity to project the magnitude, frequency and timing of potential delivery deficits, both from a Company perspective and an AOI perspective.

Once the demand forecasts were finished and the evaluation complete, the data was arranged in a fashion more conducive to IRP modeling. Specifically, the daily demand data for each individual forecast was sorted from high-to-low to create what is known as a Load Demand Curve (LDC). The LDC incorporates all the factors that will impact Intermountain's future loads. The LDC is the basic tool used to reflect demand in the IRP Optimization Model.

It is important to note that the Load Demand Curves represent existing resources and are intended to identify potential capacity constraints and to assist in the long term planning process. Plans to address any identified deficits will be discussed in the Planning Results Section of this report.

Customer Growth Summary Observations – Design Weather – All Scenarios

Idaho Falls Lateral

The Idaho Falls Lateral low growth scenario projects an increase in customers of 3,803 PY19 through PY23 (Jan 1, 2019 to Dec 31, 2023) which corresponds to an annualized growth rate of 1.49%. In the base case scenario customers are forecasted to increase by 7,772 (2.92% annualized growth rate), while the high growth scenario forecasts an increase of 10,938 customers (3.97% annualized growth rate).

Sun Valley Lateral

The Sun Valley Lateral low growth scenario (PY19 – PY23) projects an increase of 490 customers (0.89% annualized growth rate). In the base case scenario customers are projected to increase by 1,304 (2.26% annualized growth rate), while the high growth scenario shows an increase of 1,994 customers (3.34% annualized growth rate).

Canyon County Area

The low growth customer forecast (PY19 – PY23) for Canyon County Area reflects an increase of 11,395 customers (4.09% annualized growth rate). In the base case scenario customers are forecasted to increase by 14,854 (5.15% annualized growth rate), while the high growth scenario projects an increase of 17,188 customers (5.83% annualized growth rate).

State Street Lateral

The low growth customer forecast (PY19 – PY23) for the State Street Lateral reflects an increase of 4,318 customers (1.7% annualized growth rate). The base case scenario projects an increase of 7,065 customers (2.69% annualized growth rate), while the high growth scenario forecasts an increase of 10,273 customers (3.78% annualized growth rate).

Central Ada County

The low growth customer forecast (PY19 – PY23) for the Central Ada County reflects an increase of 4,397 customers (1.70% annualized growth rate). In the base case scenario customers are forecasted to increase by 6,622 (2.49% annualized growth rate), while the high growth scenario projects an increase of 8,654 customers (3.19% annualized growth rate).

Total Company

The Total Company (TC) low growth customer forecast (PY19 – PY23) projects an increase of 33,445 customers (1.91% annualized growth rate). The base case scenario forecasts an increase of 60,416 customers (3.30% annualized growth rate), while the high growth scenario projects an increase of 82,975 customers (4.37% annualized growth rate). Please note that the TC forecasts include the AOIs mentioned above as well as all other customers not located in a particular AOI.

Using the LDC analyses allows Intermountain to anticipate changes in future demand requirements and plan for the use of existing resources and the timely acquisition of additional resources.

Core Customer Distribution Sendout Summary – Design and Normal Weather – All Scenarios

Idaho Falls Lateral

IFL Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,497,806	6,851,608	6,922,846	7,021,456	7,116,751
Base	6,510,490	6,955,973	7,125,180	7,326,306	7,528,354
High	6,520,563	7,038,871	7,285,625	7,568,233	7,855,001

IFL Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,885,102	6,215,162	6,280,765	6,370,244	6,456,710
Base	5,896,701	6,309,812	6,464,327	6,646,800	6,830,116
High	5,905,923	6,384,991	6,609,880	6,866,278	7,126,459

Sun Valley Lateral

SVL Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	2,134,862	2,180,583	2,190,120	2,208,738	2,225,805
Base	2,138,646	2,212,268	2,251,525	2,300,724	2,349,482
High	2,141,970	2,240,245	2,305,777	2,380,499	2,455,144

SVL Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	1,893,932	1,934,153	1,943,094	1,959,620	1,974,756
Base	1,897,366	1,962,358	1,997,676	2,041,332	2,084,585
High	1,900,390	1,987,253	2,045,901	2,112,194	2,178,425

Canyon County Area

CCA Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,644,882	6,937,705	7,206,182	7,503,680	7,803,143
Base	6,654,154	7,022,665	7,375,106	7,762,669	8,158,671
High	6,659,942	7,075,569	7,479,998	7,931,253	8,395,219

CCA Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,278,733	5,510,136	5,723,042	5,959,382	6,197,250
Base	5,285,939	5,577,258	5,856,822	6,164,654	6,479,190
High	5,290,441	5,619,033	5,939,853	6,298,263	6,666,752

State Street Lateral

SSL Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,753,345	6,892,311	6,977,131	7,093,800	7,212,472
Base	6,761,487	6,966,876	7,122,607	7,313,601	7,509,753
High	6,770,632	7,050,715	7,287,748	7,565,565	7,853,935

SSL Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,265,382	5,374,278	5,439,666	5,530,627	5,623,132
Base	5,271,666	5,432,231	5,552,883	5,701,794	5,854,714
High	5,278,722	5,497,403	5,681,410	5,897,994	6,122,796

Central Ada County

CAC Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	6,746,456	6,868,791	6,955,257	7,073,623	7,193,992
Base	6,753,079	6,929,208	7,073,008	7,251,338	7,434,132
High	6,758,975	6,982,926	7,178,400	7,411,512	7,652,075

CAC Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	5,280,688	5,390,970	5,457,339	5,549,527	5,643,238
Base	5,285,795	5,437,905	5,548,906	5,687,765	5,830,103
High	5,290,343	5,479,616	5,630,846	5,812,362	5,999,681

Total Company

TC Design Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	46,572,743	47,636,823	48,393,973	49,290,102	50,132,353
Base	46,654,839	48,364,628	49,816,103	51,436,122	53,030,786
High	46,724,600	48,982,668	51,020,001	53,248,248	55,469,982

TC Normal Weather – Annual Core Market Distribution Sendout (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	39,209,059	40,107,255	40,738,558	41,492,753	42,201,795
Base	39,280,756	40,721,672	41,937,376	43,301,002	44,643,466
High	39,341,707	41,243,397	42,952,207	44,827,883	46,698,192

Projected Capacity Deficits – Design Weather – All Scenarios

Residential, commercial and industrial peak day load growth on Intermountain's system is forecast over the five-year period to grow at an average annual rate of 1.18% (low growth), 2.08% (base case) and 2.80% (high growth), highlighting the need for long-term planning. The next section illustrates the projected capacity deficits by AOI during the IRP planning horizon.

Idaho Falls Lateral LDC Study

When forecast peak day sendout on the Idaho Falls Lateral is matched against the existing peak day distribution capacity (88,400), peak day delivery deficit occurs under the base case scenario during PY23.

IFL Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	0	0	9
High	0	0	0	148	2901

Sun Valley Lateral LDC Study

When forecasted peak day send out on the Sun Valley Lateral is matched against the existing peak day distribution capacity (19,878 Dth), peak day delivery deficits occur in PY21-PY23 under the base case scenario.

SVL Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	221	631	1,021
High	0	0	599	1,220	1,840

Canyon County Area LDC Study

When forecasted peak day send out for the Canyon County Area is matched against the existing peak day distribution capacity (98,000 Dth), peak day delivery deficits occur in PY22-PY23 under the base case scenario.

CCA Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	1,944
Base	0	0	0	1,286	5,086
High	0	0	0	3,120	7,567

State Street Lateral LDC Study

When forecasted peak day send out for the State Street Lateral is matched against the existing peak day distribution capacity (73,000 Dth), a peak day delivery deficit occurs in PY23 under the base case scenario.

SSL Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	0	0	70
High	0	0	0	555	3,313

Central Ada County LDC Study

When forecasted peak day send out for the Central Ada County is matched against the existing peak day distribution capacity (70,000 Dth), peak day delivery deficits occur in PY22-PY23 under the base case scenario.

CAC Design Weather Peak Day Deficit Under Existing Resources (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	658
Base	0	0	0	1,130	2,931
High	0	0	363	2,638	4,992

Total Company LDC Study

The Total Company perspective differs from the laterals in that it reflects the amount of gas that can be delivered to Intermountain via the various resources on the interstate system. Hence, total system deliveries should provide at least the net sum demand – or the total available distribution capacity where applicable - of all the laterals/AOIs on the distribution system. The following table shows that there are no peak day deficits based on existing resources.

TC Design Weather Peak Day Surplus (Deficit) (Dth)					
Growth Scenario	2019	2020	2021	2022	2023
Low	0	0	0	0	0
Base	0	0	0	0	0
High	0	0	0	0	0

2019 IRP vs. 2017 IRP Common Year Comparisons

This section compares the Total Company and each AOI during the three common years of the 2019 and 2017 IRP filings. In some cases, the distribution transportation capacity is forecast to be lower in the 2019 IRP than it was in the 2017 IRP. This is the result of differences in, or fine tuning of, planned capacity upgrades.

Total Company Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2019	435,879	145,199	581,078
2020	450,704	146,407	597,111
2021	466,361	146,729	613,090

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2019	415,543	143,335	558,878
2020	426,723	145,335	572,058
2021	438,049	145,335	583,384

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – TC USAGE DESIGN BASE CASE Over/(Under) 2017 IRP (Dth)			
	Peak Day Sendout		
	Core Market	Firm CD[1]	Total
2019	20,336	1,864	22,200
2020	23,981	1,072	25,053
2021	28,312	1,394	29,706

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Total Company Peak Day Deliverability Comparison

2019 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)			
	2019	**2020**	**2021**
Maximum Daily Storage Withdrawals:			
Nampa LNG	60,000	60,000	60,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	245,512	245,512	245,512
Maximum Deliverability (NWP)	297,650	315,099	297,043
Total Peak Day Deliverability	543,162	560,611	542,555

2017 IRP PEAK DAY FIRM DELIVERY CAPABILITY (Dth)			
	2019	**2020**	**2021**
Maximum Daily Storage Withdrawals:			
Nampa LNG	60,000	60,000	60,000
Plymouth LS	155,175	155,175	155,175
Jackson Prairie SGS	30,337	30,337	30,337
Total Storage	245,512	245,512	245,512
Maximum Deliverability (NWP)	281,345	281,345	281,345
Total Peak Day Deliverability	526,857	526,857	526,857

2019 IRP PEAK DAY FIRM DELIVERY CAPABILITY Over/(Under) 2017 (Dth)			
	2019	2020	2021
Maximum Daily Storage Withdrawals:			
Nampa LNG	0	0	0
Plymouth LS	0	0	0
Jackson Prairie SGS	0	0	0
Total Storage	0	0	0
Maximum Deliverability (NWP)	16,305	33,754	15,698
Total Peak Day Deliverability	16,305	33,754	15,698

Idaho Falls Lateral Design Weather/Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	88,400	59,686	21,011	80,697
2020	88,400	61,352	21,311	82,663
2021	88,400	63,154	21,469	84,623

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	88,700	59,936	19,391	79,327
2020	88,700	61,819	19,391	81,210
2021	88,700	63,730	19,391	83,121

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – IFL USAGE DESIGN BASE CASE Over/(Under) 2017 IRP (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	(300)	(250)	1,620	1,370
2020	(300)	(467)	1,920	1,453
2021	(300)	(576)	2,078	1,502

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Sun Valley Lateral Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – SVL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	19,878	17,890	1,335	19,225
2020	19,878	18,287	1,375	19,662
2021	19,878	18,704	1,395	20,099

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	19,950	15,656	1,335	16,991
2020	19,950	15,875	1,335	17,210
2021	19,950	16,098	1,335	17,433

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE –SVL USAGE DESIGN BASE CASE

Over/(Under) 2017 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	(72)	2,234	0	2,234
2020	(72)	2,412	40	2,452
2021	(72)	2,606	60	2,666

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Canyon County Area Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)

	Distribution Transport Capacity	Peak Day Sendout		
		Core Market	Firm CD[1]	Total
2019	98,000	63,269	25,395	88,664
2020	98,000	66,670	25,395	92,065
2021	98,000	70,339	25,218	95,557

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE (Dth)

	Distribution Transport Capacity	Peak Day Sendout		
		Core Market	Firm CD[1]	Total
2019	93,000	60,921	26,320	87,241
2020	93,000	63,472	26,320	89,792
2021	93,000	65,997	26,320	92,317

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – CCA USAGE DESIGN BASE CASE

Over/(Under) 2017 (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	5,000	2,348	(925)	1,423
2020	5,000	3,198	(925)	2,273
2021	5,000	4,342	(1,102)	3,240

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

State Street Lateral Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	73,000	64,634	1,220	65,854
2020	73,000	66,367	1,220	67,587
2021	73,000	68,146	1,220	69,366

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	67,000	62,308	2,630	64,938
2020	76,500	65,613	2,630	68,243
2021	76,500	67,269	2,630	69,899

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – SSL USAGE DESIGN BASE CASE Over/(Under) 2017 (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	6,000	2,326	(1,410)	916
2020	(3,500)	754	(1,410)	(656)
2021	(3,500)	877	(1,410)	(533)

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Central Ada County Design Weather/ Base Case Growth Comparison

2019 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	70,000	64,631	1,410	66,041
2020	70,000	66,261	1,410	67,671
2021	70,000	67,932	1,448	69,380

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2017 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE (Dth)

		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2019	71,000	61,730	1,490	63,220
2020	71,000	62,832	1,490	64,322
2021	71,000	63,980	1,490	65,470

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

2019 IRP LOAD DEMAND CURVE – CAC USAGE DESIGN BASE CASE Over/(Under) 2017 (Dth)				
		Peak Day Sendout		
	Distribution Transport Capacity	Core Market	Firm CD[1]	Total
2017	(1,000)	2,901	(80)	2,821
2018	(1,000)	3,429	(80)	3,349
2019	(1,000)	3,952	(42)	3,910

[1]Existing firm contract demand includes LV-1 and T-4 requirements.

Resource Optimization

Introduction

Intermountain's IRP utilizes an optimization model that selects resource amounts over a pre-determined planning horizon to meet forecasted loads by minimizing the present value of resource costs. The model evaluates and selects the least cost mix of supply and transportation resources utilizing a standard mathematical technique called linear programming. Essentially, the model integrates/coordinates all the individual functional components of the IRP such as demand, supply, demand side management, transport and supply into a least cost mix of resources that meet demands over the five-year IRP planning horizon, 2019 to 2023.

This section of the IRP report will first describe the functional components of the model, then the model structure and then its assumptions in general. At the end, model results will be discussed.

Functional Components of the Model

The optimization model has the following functional components:

- Demand Forecast by AOI
- Supply Resources, Storage and Supply, by Area
- Transportation Capacity Resources, Local Laterals and Major Pipelines, Between Areas
- Non-Traditional Resources such as Demand Side Management

Underlying these functional components is a model structure that has gas supply and demand by area (nodes) with gas transported by major pipelines and local distribution laterals (arcs) between supply and demand. This model mirrors, in general, how Intermountain's delivery system contractually and operationally functions. In any IRP model, there must be a balance between modeling in sufficient detail to capture all major economic impacts while, at the same time, simplifying the system so that the model operates efficiently and the results are understandable and auditable. Since Intermountain's model evaluates gas supply and capacity additions over a five year period, the model was designed so that only the major elements are recognized. This is in contrast to a dispatch model which needs to balance every detail precisely and so requires a level of detail that is fully representative of all daily system requirements. For this reason, a more simplified structure is utilized in the Company's IRP model.

Model Structure

In order to develop a basic understanding of how gas supply flows from the various receipt points to ultimate delivery to the Company's end-use customers, a graphical representation of IGC is helpful. Figure 42 is a medium detail map of the IGC system. Generally, gas flows from supply areas (nodes) such as Canada and the Rockies, and from storage in Washington state and Clay

Basin in the Rockies region (nodes), across major pipelines (arcs) to southern Idaho. In southern Idaho, the gas is transported to demand areas (nodes) by local distribution laterals. The model utilizes a simplified but generally correct structure of the Figure 42 map.

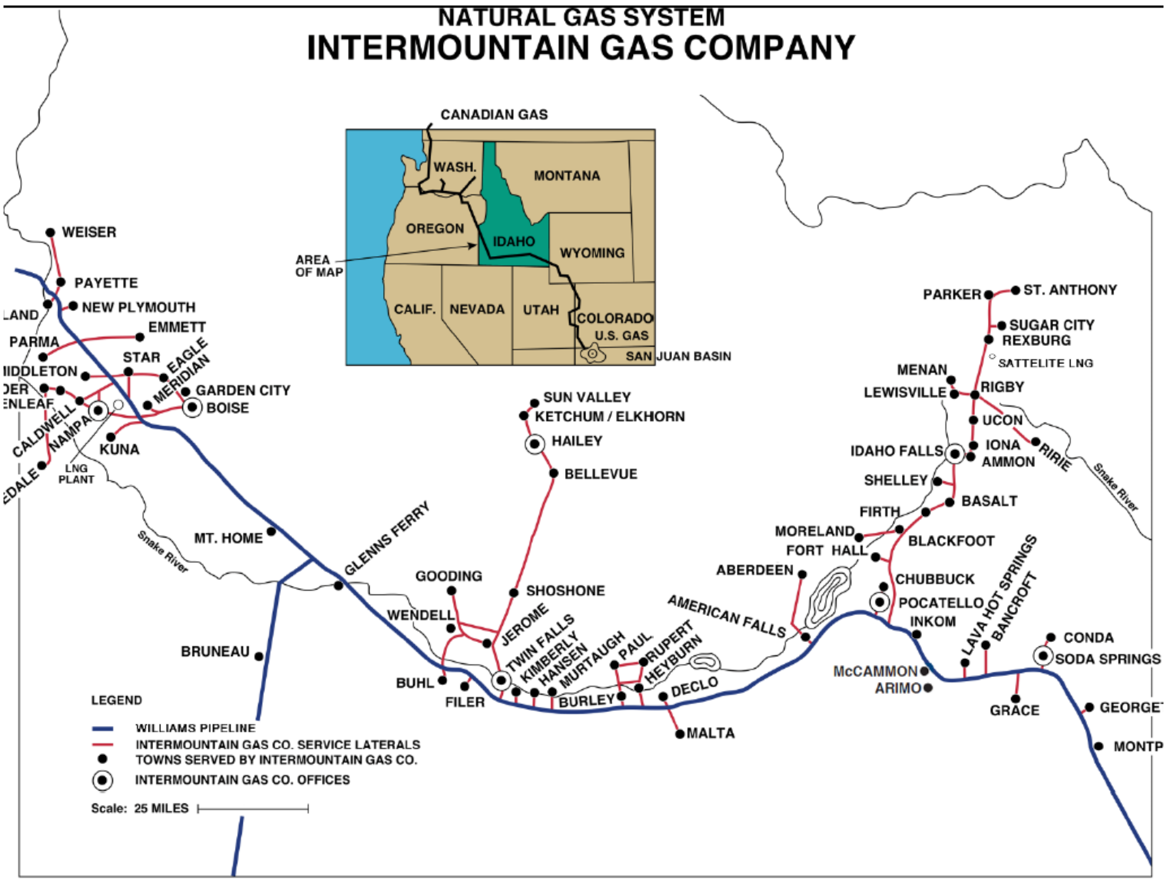


Figure 42: Natural Gas System Map – Intermountain Gas Company

Figure 43 presents the model of system flows by major pipelines and supply areas. Figure 43 shows four major supply receipt areas including Sumas, Stanfield, AECO and Rockies with ultimate delivery to IMG, southern Idaho.

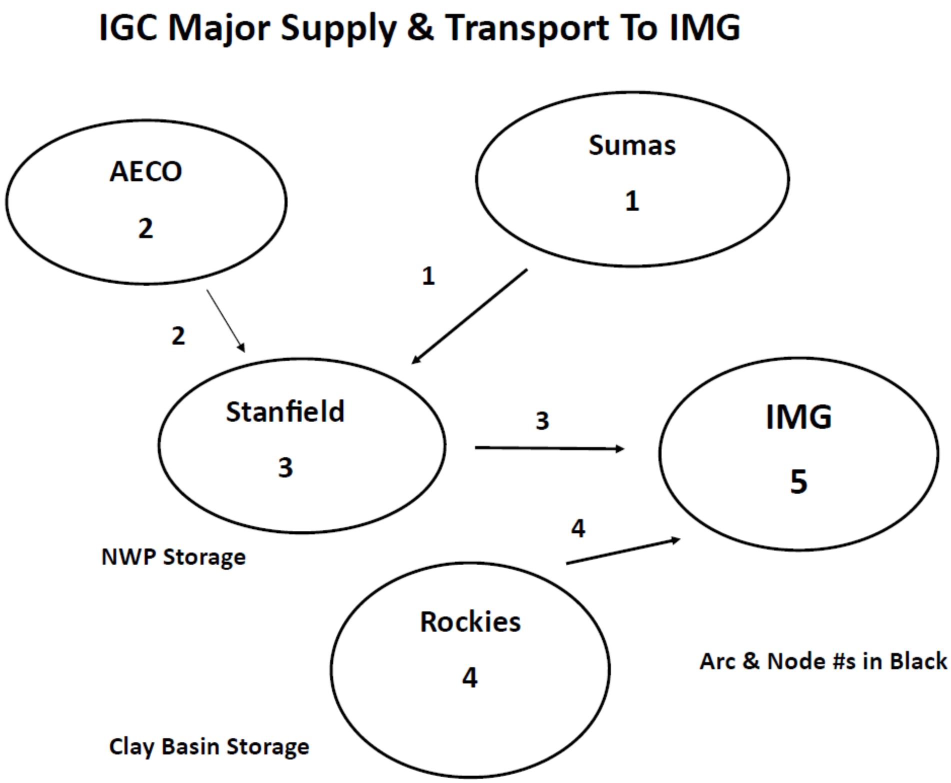


Figure 43: IGC Major Supply and Transport to IMG

Supplies from those supply receipt areas(nodes) are then delivered and aggregated at the IMG pool node where they are allocated to be delivered to the appropriate demand areas (nodes), or AOIs, by local distribution laterals (arcs) as depicted in Figure 44.

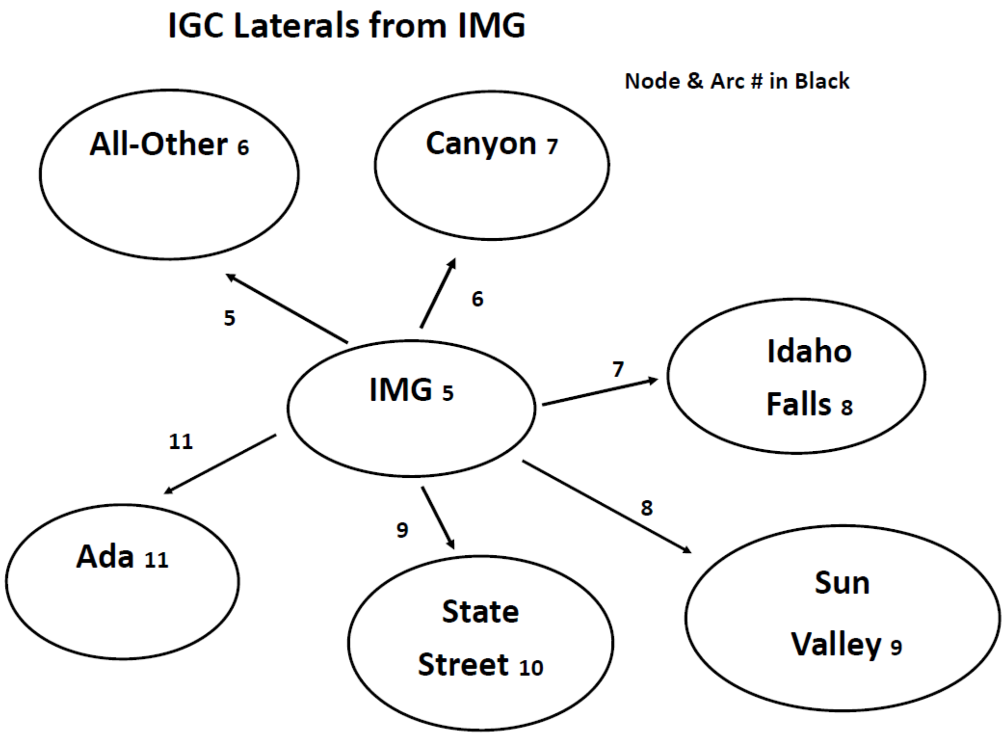


Figure 44: IGC Laterals from IMG

The final demand areas are the following as per Figure 44:

- Central Ada Area
- State Street Lateral
- Canyon County Region
- Idaho Falls Lateral
- Sun Valley Lateral
- All Other

The sum of all six areas is equal to system gas demand. A map of the AOIs is included at the end of the Executive Summary Section.

These map symbols were converted into a mathematical system of reference numbers so that a system of numbered arcs and nodes reflect physical locations on the map for the model. The resultant set of numbered arcs and nodes are shown on Table 14.

Table 14: Definition of Arcs & Nodes by Reference Number

Definition of Arcs & Nodes by Reference #s					
	Area/Node From		Area/Node To		
ARC #	Name	Area #	Name	Area #	Note
1	Sumas	1	Stanfield	3	Western Canada Gas
2	AECO	2	Stanfield	3	Alberta Gas
3	Stanfield	3	IMG	5	NWP path with NWP Storage
4	Rockies	4	IMG	5	Clay Basis & all south of IMG
5	IMG	5	All-Other	6	IGC Laterals from IMG
6	IMG	5	Canyon	7	IGC Laterals from IMG
7	IMG	5	Idaho Falls	8	IGC Laterals from IMG
8	IMG	5	Sun Valley	9	IGC Laterals from IMG
9	IMG	5	State St	10	IGC Laterals from IMG
10	IMG	5	Ada	11	IGC Laterals from IMG

Demand Area Forecasts

As previously discussed in the Load Demand Curves Section beginning on page 90, demands are forecasted using a unique LDC for each AOI. These LDCs are over a gas supply year for daily gas usage in MMBTU, nominally 365 days. To simplify the modeling, the LDC was aggregated into 12 homogenous periods with similar load characteristics, and then loads for each of those periods were averaged. Table 15 defines the periods used. The resultant demand curve represents load changes over the entire year but with a minimum of data points. Figure 45 depicts an example LDC aggregated into those homogenous groups. Figure 45 has ordered the demands from high to low for the full 365 days. Each aggregated level reflects one period modeled in the optimization model (i.e. the bold horizontal lines). The model recognizes the number of days in each period and computes the total flow per period.

Table 15: Periods for Optimization Modeling

Period	Days in Period	Cumul. Days in Period
1	1	1
2	1	2
3	2	4
4	5	9
5	8	17
6	14	31
7	31	62
8	28	90
9	61	151
10	61	212
11	61	273
12	92	365

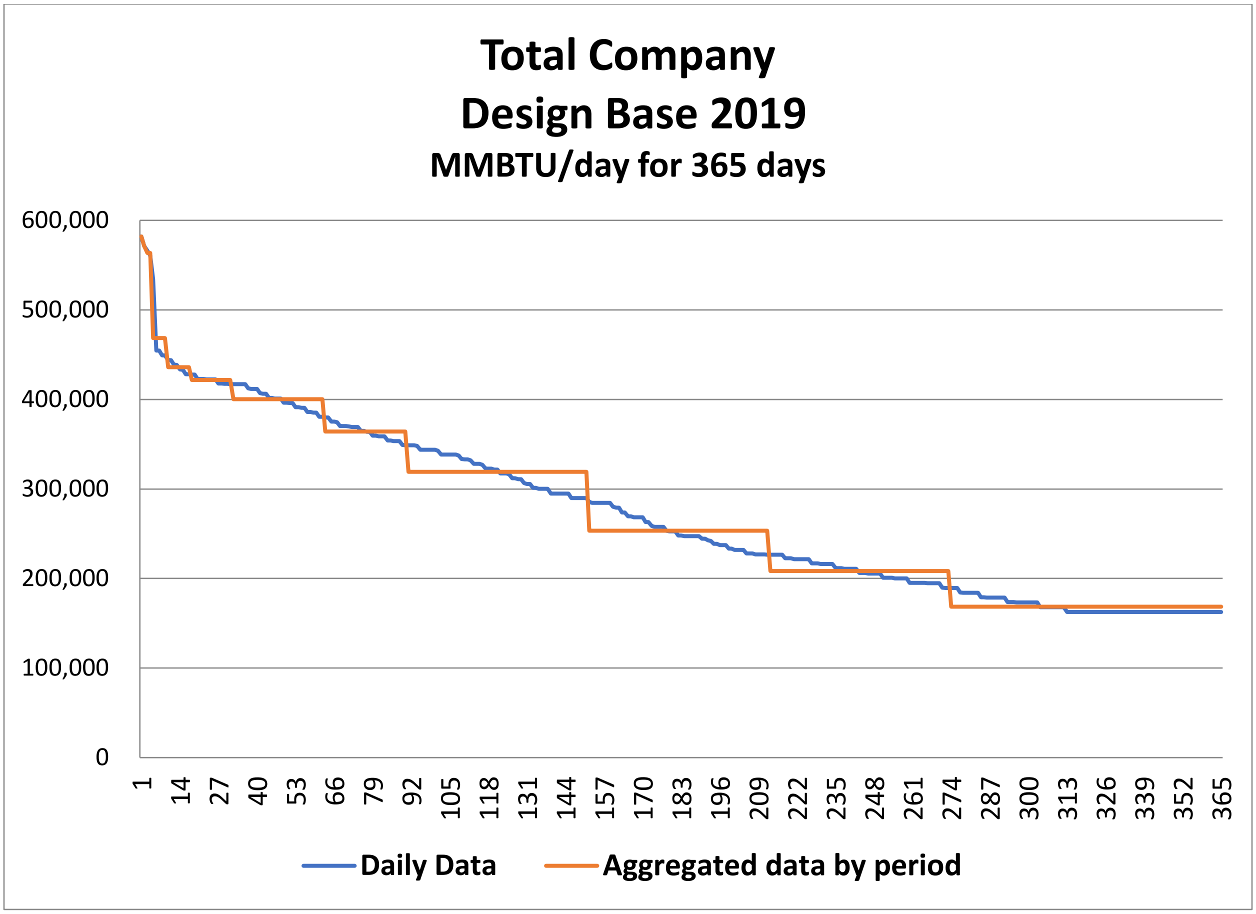


Figure 45: Total Company Design Base 2019

The model is also programmed to recognize that Intermountain must provide gas supply and both interstate and distribution transportation for its core market and LV-1 customers, but only firm distribution capacity for T-4 customers. T-3 is interruptible distribution capacity and as such is not included. Because Intermountain is contractually obligated to provide each day a certain level of firm transport capacity for its firm transporters, the industrial demand forecast for these customers is not load-shaped but reflects the aggregate firm industrial CD for each class by specific node for each period in the LDC.

Scenarios for the load demand curves are by weather and customer growth which are described elsewhere in this report. The weather scenarios are normal weather and design weather. Customer growth is separated into low growth, base case and high growth scenarios. This results in a total of six scenarios. The combination of the design weather and base case scenarios (Design Base) form the critical planning scenario for the report and will be reported as the main optimization results. Other scenarios are also available, but all others, except for the combined scenarios of design weather and high growth, would have sufficient resources as long as the Design Base does.

Supply Resources

Resource options for the model are of two types: supply resources and storage contracts, which, from a modeling standpoint, are utilized in a similar manner. All resources have beginning and ending years of availability, periods of availability, must take usage, period and annual flow capability and a peak day capability. Supply resources have price/cost information entered in the model over all points on the load demand curve for the study period. Additionally, information relating to storage resources includes injection period, injection rate, fuel losses and other storage related parameters.

Each resource must be sourced from a specific receipt point or supply area. One advantage of citygate supplies and certain storage withdrawals is that they do not utilize any of Intermountain's existing interstate capacity as the resource is either sited within a demand area node or are bundled with their own specific redelivery capacity. Supply resources from British Columbia are delivered into the Northwest system at Sumas while Rockies supplies are received from receipt pools known as North of Green River and South of Green River. Alberta supplies are delivered to Northwest's Stanfield interconnect utilizing available upstream capacity - the available quantity at Stanfield is the limiting factor regardless of capacity of any single upstream pipeline (AECO-Stanfield arc). Each supply resource utilizes transport arc(s) that reach the IMG node from its supply receipt node.

From a model perspective, the DSM resources are considered a subset of supply resources and fill demand needs on the applicable node by offsetting other supply resources when the cost of such is less than other available resources. These DSM resources have costs and resource capacity that were determined by a separate DSM analysis as detailed in the Core Market Energy Efficiency Section (starting on page 73).

Transport Resources

Transport resources are explicitly associated with arcs in the model which represent the way supplies flow from specific receipt areas to Intermountain's ultimate receipt pool identified as IMG, where all supplies are pooled for ultimate delivery into the Company's various demand nodes. Transport resources reflect contracts for interstate capacity, primarily on Northwest Pipeline, but also for the three separate pipelines that deliver gas supplies to Northwest's Stanfield interconnect from AECO. Because these pipelines operate in a serial fashion and have nearly identical flow capabilities, for modeling purposes, they are treated as one arc and are referred to as upstream capacity for gas originating at AECO and ending at Stanfield. There are also arcs reflecting each of the individual laterals representing the Areas of Interest. For example, supply resources to be delivered from Sumas to Idaho Falls, first must use the Sumas to Stanfield arc, the Stanfield to IMG arc and from there flow from IMG to the Idaho Falls arc. This ensures that the total supply deliveries cannot exceed total demand including laterals. Supplies such as the Rexburg LNG are already located on Intermountain's distribution system on a specific demand lateral and therefore do not require interstate pipeline transportation. The system representation recognizes Northwest's postage stamp pricing and capacity release.

Transport resources have a peak day capability and are assumed to be available year round unless otherwise noted. Transport resources can have different cost and capabilities assigned to them as well as different years of availability.

Model Operation

The selection of a least cost mix of resources, or resource optimization, is based on the cost, availability and capability of the available resources as compared to the projected loads at each of the nodes. The model chooses the mix of resources which meet the optimization goal of minimizing the present value cost of delivering gas supply to meet customer demand. The model recognizes contractual take commitments and all resources are evaluated for reasonableness prior to input. Both the fixed and variable costs of transport, storage and supply can be included. The model will exclude resources it deems too expensive compared to other available alternatives.

The model can treat fixed costs as sunk costs for certain resources already under contract. If a fixed cost or annual cost is entered for a resource, the model can include that cost for the resource in the selection process, if directed, which will influence its inclusion vis-à-vis other available resources. If certain resources are committed to and the associated fixed cost will be paid regardless of the level of usage, only the variable cost of that resource is considered during the selection process, but the fixed cost is included in the summary. However, any new resources, which would be additional to the resource mix, will be evaluated using both fixed and variable costs. For cost summary purposes, fixed costs were included, whether sunk or included in the least cost present value optimization, to approximate the expected revenue requirement for transport and supply.

The model operates in a PC environment. The various inputs are loaded via an Excel spreadsheet where they are loaded and utilized by PC linear programming software. The model is run by first launching the optimization software, opening the Excel model containing all the appropriate scenario of demand, supply, storage and capacity inputs (including all the correct prices) and calling up the correct constraint model set. The optimization software links the inputs to the constraint model, optimizes all resources to the period demands. Once the model computes the least cost resource mix, the results are organized by a set of macros that writes the output back into the same Excel model which simplifies, and minimizes the time, to audit and evaluate the model for reasonableness and accuracy.

Special Constraints

As stated earlier, the model minimizes cost while satisfying demand and operational constraints. Several constraints specific to Intermountain's system were modeled in the IRP model.

- Nampa LNG storage does not require redelivery transport capacity. Both SGS and LS storage are bundled with firm delivery capacity; transportation utilization of this capacity matches storage withdrawal from these facilities. SGS, LS and Clay Basin must be injected in the summer.

- All core market and LV-1 sales loads are completely bundled.

- T-4 customer transportation requirements utilize only Intermountain's distribution capacity. The T-4 firm CD is input as a no-cost supply delivered at IMG. T-3 is an interruptible distribution industrial rate and as such is not included.

- Traditional resources destined for a specific lateral node must be first transported to the IMG pool and then from IMG to the lateral node.

- Non-traditional resources such as mobile LNG that are designed to serve a specific lateral can only be employed when lateral capacity is otherwise fully utilized.

Model Inputs

The optimization model utilizes these three inputs which do not vary by scenario:

- Transport Resources
- Supply Resources by Year
- LDC Price Format for Supply Resources by Yearly Periods

These input tables are in Exhibit 7, Model Input Tables For All Scenarios. The one input table that does vary is the LDC table, which is the scenario referenced directly in this report. The Design Weather LDC is in Exhibit 8, Design Weather Load Demand Curve. Snapshots of Input and Output Tables where relevant are displayed below with descriptions and without formal numbering so as not to confuse other labeling.

Each resource, whether supply or transport, is given a resource number, name and an acronym and appropriate parameters as per Supply Resources by Year input tables in Exhibit 7. Table 14 and Figures 43 & 44 above have a summary of arcs and nodes referenced in these input tables. For example, in the Supply Resource Year 1, resource #1 is Shell Stanfield Winter, ShSta-W, see Figure 46. The resource is available for periods 1-9, at a max capacity of 10,000 MMBTU/day and a must use 1,510,000 MMBTU annually. It is delivered at Stanfield, node 3. Possible utilization rates can be set from 0% to 100%. Must take resources can be set with utilization rates set at a min/max of 100% or set an annual rate as ShSta-W was. Period 9 in the example below allows this period to balance to the annual must take.

Weather: Design
Growth: Base/Price: Base

Supply Resource data input sheet by year: Min/Max Utilzation Rate
Intermountain Gas IRP Model
2019-2023 IGC IRP

	Year	1	2019		per day/	Assoc.	info		12 Number of periods of Utilization Rates (UR)									
50			Area		annual	Transport	Period		Min Max of UR by period from range set :use beg;end as guide									
#	Full name & Notes	Acronym	Delivered	#	mmbtu	Days	beg/end		1	2	3	4	5	6	7	8	9	10
1	Shell Stanfied Winter	ShSta-W	Stanfield	3	10,000	none	1	Min	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00
1.5	firm winter	must take	100%		1,510,000	151.0	9	Max	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00

Figure 46: Supply Resource Data Input Sheet

Demand side management resources are labeled by the year they are providing supply across all programs. For example, DSM20 represents the amount of DSM supplied in 2020. Annual DSM study amounts were distributed to periods by residential seasonal usage patterns. Note, new DSM resources start in 2020.

The model selects the best cost portfolio based on least cost of present value resource costs over the planning horizon. However, it also has been designed to comply with operational and contractual constraints that exist in the real world (i.e. if the most inexpensive supply is located at Sumas, the model can only take as much as can be transported from that point; additionally, it will not take inexpensive spot gas until all constraints related to term gas or storage are fulfilled). In order for the results to provide a reasonable representation of actual operations, all existing resources that have committed must-take contracts are assigned as “must run” resources. The Company’s minimal commitment for summer must-take supplies means that those supplies do not exceed demand. In the real world, having excess summer supplies results in selling those volumes into the market at the then prevailing prices whereas the model only identifies those volumes and related cost. Please note that this level of sales is small relative to total supply.

Another important assumption relates to the supply fill or balancing options. Supply fill resources provide intelligence as to where and how much of any deficit in any existing resource exists; the model treats them as economic commodities, meaning that availability is dynamic up to its maximum capability. The model can select available fill supply at any node, for any period and in any volume that it needs to help fill capacity constraints. To ensure that the model provides results that mirror reality, these supplies have been aggregated into peak, winter, summer and annual price periods. Each aggregated group has a different relative price with the peak price being the highest, and the summer price being the lowest. Additionally, since term pricing is normally based on the monthly spot index price, no attempt has been made to develop fixed pricing for fill resources but each such resource includes a reasonable market premium if applicable.

The storage injection table provides the amount of resources injected into the various storage facilities for which Intermountain retains direct control. Reflective of real-world cycling constraints, storage may only be withdrawn in the peak and/or winter periods and injections may only occur in summer periods.

In the LDC Price input table in Exhibit 7, prices for supply, except DSM, are based on the official IRP three hub price forecast (AECO, Sumas and Rockies). DSM pricing is based on an avoided cost study (starting on page 84) that has the hub prices forecast as an input.

All transport resources have specific arc numbers with to and from nodes specified as per the Transport Resource input table in Exhibit 7. Capability and pricing are included by resource. Transport resources that are existing pipeline and laterals including transport resources 5 through 8 that are tied to NWP storage resources are labeled as such. Proposed expansions of these are labeled as such. Transport fill resources represent expensive resources that provide a gap resource when there are not enough resources available. Three special alternative resources, 24, 25 and 28 (Canyon, Sun Valley and Ada) represent special resources that were developed as alternatives to preferred lateral expansions. This is in distinction to supply fill resources which represent balancing resources that can be acquired quickly.

Model Results

The optimization model results for the design weather, base price and base case scenario for the years 2019 through 2023 are presented and discussed below. The results of the model are summarized, for each scenario using the tables described below:

- Lateral Summary All Years
- Supply Summary All Years
- Annual Cost Summary All Years
- Supply Resource Usage Tables (Includes Flow and Capacity by Year and Period)
- Storage Injection Usage Tables (Includes Flow, Injection and Capacity by Year and Period)
- Transport Usage Tables (Includes Both Period and Annual Capacity Used by Year)

Exhibit 9, Design Base Output Tables shows the tables just described for the five periods of the Design Base case.

Model Output for Design Base Scenario

The following provides a description of the information presented by type of output tables in Exhibit 9 and the implication for the Design Base scenario.

The Lateral Summary Tables All Years provides a snapshot by year of whether a specific lateral to an AOI needs an expansion and whether that expansion is a preferred one as opposed to a fill or an alternative lateral resource. On the next page is the first year of the Lateral Summary Tables All Years, for the Design Base scenario, Figure 47.

The “Peak Day LDC” column is from the Design Base scenario and represents the load that must be met by lateral resources. The “Existing Lateral Capacity” column is the current existing capacity. The “Expansion Lateral Capacity” column represents the preferred planned expansion. The “Deficit of Existing” column represents the gap between demand and existing resources. If this column shows that additional capacity is needed, the model will select from a list of available enhancements outlined earlier in this report. If the “Fill/Alt. Lateral Capacity” column is zero, then there is sufficient planned expansion and existing capacity such that there is no resource gap. The table for year 1 displays that condition as do all the years for the Design Base scenario (Exhibit 9) so there is no resource gap. This is accomplished by planned expansions meeting new load.

Lateral Capacity Summary By Year
2019-2023 IGC IRP / Weather: Design / Growth: Base / Price: Base

Year	1	2019

MMBTU per day

Demand Node	Peak Day LDC	Existing Lateral Capacity	Expansion Lateral Capacity	Fill/Alt. Lateral Capacity	Existing + Expansion Capacity	Deficit of Existing
All-Other	260,597	296,029	0	0	296,029	0
Canyon	88,664	98,000	0	0	98,000	0
Idaho Falls (W LNG)	80,697	88,400	0	0	88,400	0
Sun Valley	19,225	19,878	0	0	19,878	0
State St	65,854	73,000	0	0	73,000	0
Ada	66,041	70,000	0	0	70,000	0
	581,078	645,307	0	0	645,307	0

Figure 47: Lateral Capacity Summary by Year

The Supply Usage Summary, Figure 48, is displayed below for the fifth year of the Design Base scenario study. All five years are provided in output Exhibit 9. It provides a general summary by major area as opposed to individual resources including DSM.

Year 5
IRP Model Summary Result, Supply in MMBTU per Day by Node Delivered by Period

Supply Area	Period 1	Period 2	Period 3	Period 4	Period 5	Period 6	Period 7	Period 8	Period 9	Period 10	Period 11	Period 12
Sumas	0	0	0	0	0	0	0	0	0	13,847	2,641	0
AECO	112,200	112,200	112,200	112,200	112,200	112,200	112,200	112,200	112,200	112,200	86,100	70,577
Stanfield	195,512	195,512	195,512	185,212	95,771	77,635	65,771	23,746	28,111	17,570	0	0
Rockies	110,114	101,082	95,116	70,820	110,114	110,114	110,114	110,114	71,551	40,000	40,000	36,466
IMG	220,476	217,630	217,630	217,630	165,686	165,686	165,686	165,686	165,686	162,733	157,630	157,630
All-Other	7,027	6,857	6,728	5,199	4,678	4,446	4,110	3,524	2,799	1,743	1,017	375
Canyon	0	0	0	0	0	0	0	0	0	0	0	0
Idaho Falls	0	0	0	0	0	0	0	0	0	0	0	0
Sun Valley	0	0	0	0	0	0	0	0	0	0	0	0
State St	0	0	0	0	0	0	0	0	0	0	0	0
Ada	0	0	0	0	0	0	0	0	0	0	0	0
Totals	645,330	633,281	627,186	591,061	488,449	470,081	457,881	415,270	380,348	348,093	287,388	265,048
LDC	645,330	633,281	627,186	591,061	488,449	470,081	457,881	415,270	380,348	308,093	241,443	199,030
O/U	0	0	0	0	0	0	0	*0*	*0*	*40,000*	*45,945*	*66,019*

Figure 48: Supply Usage Summary

The figure on the previous page provides supply by area by LDC period for a specified year. The LDC demands on the second to last line, LDC is the actual LDC demand by period for the year. The line above, Totals, is the actual gas supply and will match the LDC demand for periods 1-9. The supply will exceed the LDC demand for periods 10-12 representing injections needed for storage, the over/under line, "O/U". Sumas is utilized for supply of a portion of this injection gas consistent with planned operation. DSM will be in the All Other node as indicated above. Small LNG storage, such as Rexburg is treated as a lateral resource. For all years of the Design Base scenario, there are sufficient supply resources with DSM providing a portion of supply at avoided cost.

The Annual Cost Summary All Years table provides supply and transport costs by years that would very roughly approximate the fixed and variable cost of the revenue requirement. Under the Design Base scenario, costs are much higher than an actual year, so their level is not itself meaningful. The present value of these costs is also presented. The model will optimize on the least cost of the present value of the transport and supply costs designated in the model. The graph of the supply price hubs forecast is presented since it shows that there was a recent price spike in 2019 with a decline afterward which flattens out. The supply costs decline accordingly then rise. Cheaper fixed supply contracts end toward the end of the study period resulting in higher priced supply. Transport is fairly constant.

Supply Resource Usage output tables and Storage Injection Usage output tables contain detailed output data by resource by period by year. The input table discussion above provides a guide to the organization of the data. The information provided in the discussed Supply Summary output table provides a much broader overview of the supply situation.

The supply resources in the detailed output tables have the following output parameters:

- Utilization Rates by Period by Year
- Capacity Used by Period by Year
- Flow Used by Period by Year

The utilization rate is between 0.0 and 1.0 with 1.0 representing 100% utilization of the capacity of the resource. This is the easiest output parameter to check for a resource being used properly. The capacity used per period is simply capacity times the utilization rate. The flow is the volume as computed by days per period times the capability used.

Supply resources 1-3 represent must-take contracts that have total volumes that meet the contract amounts as demonstrated by the output related to volumes. The model does some minor adjustment between periods. Supply resources 4-6 represent balancing resources by major hub and as demonstrated by the output tables varies as needed to balance the system. AECO supply resources 7-11 act as the must run resources meeting transport constraints in the output tables. Storage resources 14-19 have proper summer injection to provide winter peak resources in the output tables. Resource 13 represents T-4 customers that purchase their own supply and transport where the model delivers it at IMG for free. Lastly, DSM is utilized as expected in the output tables. The model chooses DSM as a resource when it is the least cost option based on its avoided cost.

Transport Usage Tables provide utilization rates and capacity used by transport resource by period by year. As discussed above, fill and alternative transport resources provide a gap analysis indication when the system is sized too small. Transport resources 19 to 28 represent these fill and alternative transport resources and none of these resources are utilized for any of the years for the Design Base scenario output tables. This indicates planned expansions are adequate to meet Design Base scenario peak needs.

Other Scenarios

Other scenarios with LDC input files and output tables are in Exhibit 10.

Summary

In summary the optimization model:

- Employs utility standard practice method to optimize the system via linear programming.
- Models DSM and storage.
- Handles storage withdrawal and injection across seasons.
- Provides a gap analysis on the need for lateral expansion not preferred.
- Provides a check on transport and supply capacity.
- Has convenient Excel spreadsheet input/output.

Planning Results

Throughout previous sections of the IRP it has been shown that projected growth throughout Intermountain's distribution system could possibly create capacity deficits in the future. Through the use of a gas optimization modeling system that incorporates total customer loads, existing pipe and system configurations along with current distribution system capacities, each potential deficit has been defined with respect to timing and magnitude. If any such deficit occurs, then an evaluation of system capacity enhancements is performed.

The five identified Areas of Interest that were analyzed under design conditions are: the State Street Lateral, Central Ada County, Canyon County, the Idaho Falls Lateral and the Sun Valley Lateral. Each of these areas are unique in their customer growth and pipeline characteristics, and the optimization of each requires different enhancement solutions.

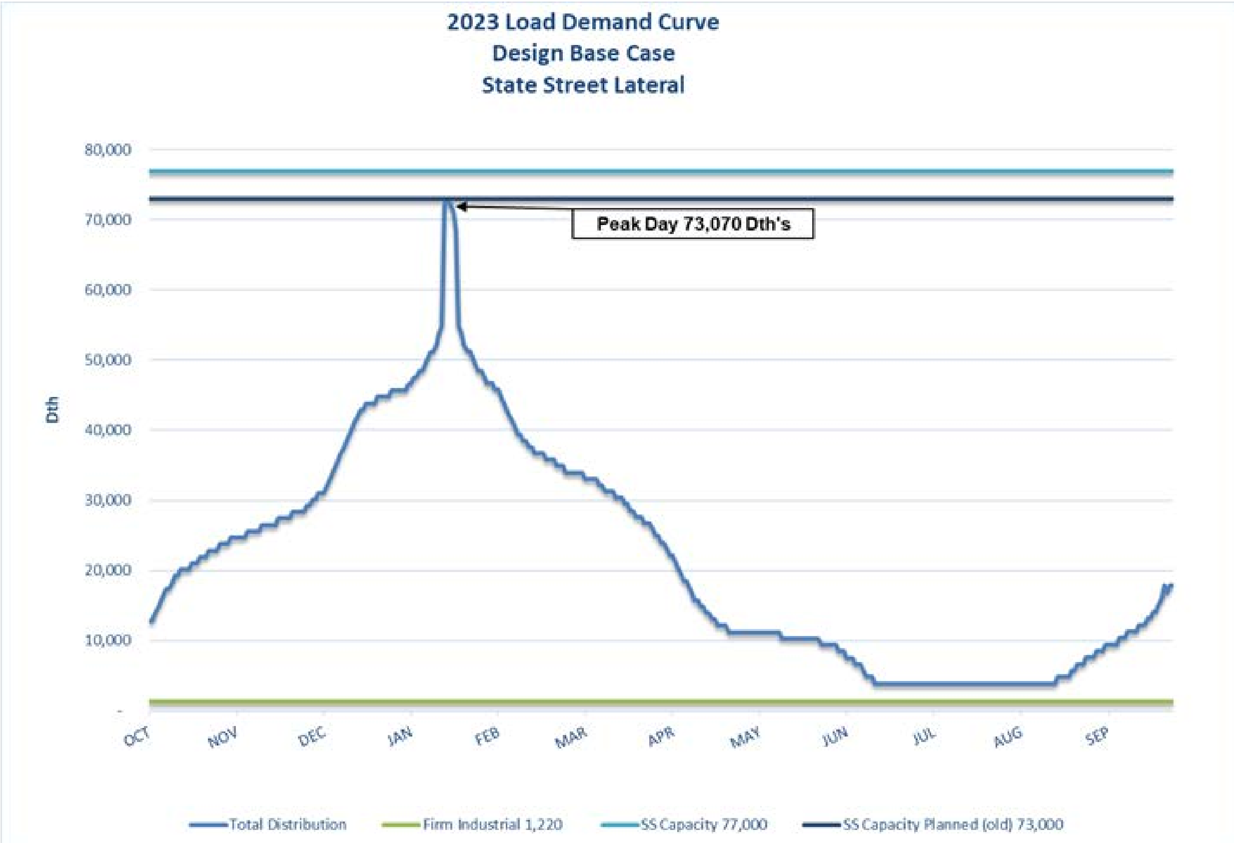
After discussing the enhancement solutions for the forecasted capacity deficits, this section will also compare the peak delivery deficits of the total Company as well as each AOI during the three common years of the 2019 and 2017 IRP filings.

State Street Lateral

The State Street Lateral is a 16-mile stretch of high pressure, large diameter main that begins in Caldwell and runs east along State Street serving the towns of Star, north Meridian, Eagle and into northern Boise. The lateral is fed directly from a gate station along with a back feed from another high-pressure pipeline from the south. Much of the pipeline is closely surrounded by residential and commercial structures that create a difficult situation for construction and/or large land acquisition, thus making a compressor station or LNG equipment less favorable. A complete review of the situation shows it is ideally suited to perform a pipeline retest that will establish a higher maximum allowable operating pressure and thus allow the Company to maximize the potential of its existing facilities before investing in new infrastructure. The retest can be performed in phases over multiple years which will provide increased capacity as actual growth is experienced, and phasing will minimize the length of pipe that must be taken out of service at one time.

The State Street retest enhancement is required within this IRP five-year outlook. The first phase of retesting will be completed in 2019. Phase one of the retest begins at the gate station and spans a 6.6-mile section downstream, ending near the intersection of State Street and Highway 16. With projected growth on the lateral, the second phase of retesting is required for the 2022 construction season and is currently planned for a 3-mile section extending east of Highway 16. Phase two of the State Street retest project will provide capacity beyond the IRP planning horizon.

The graph below shows no deficit with the proposed capacity under the base case scenario.

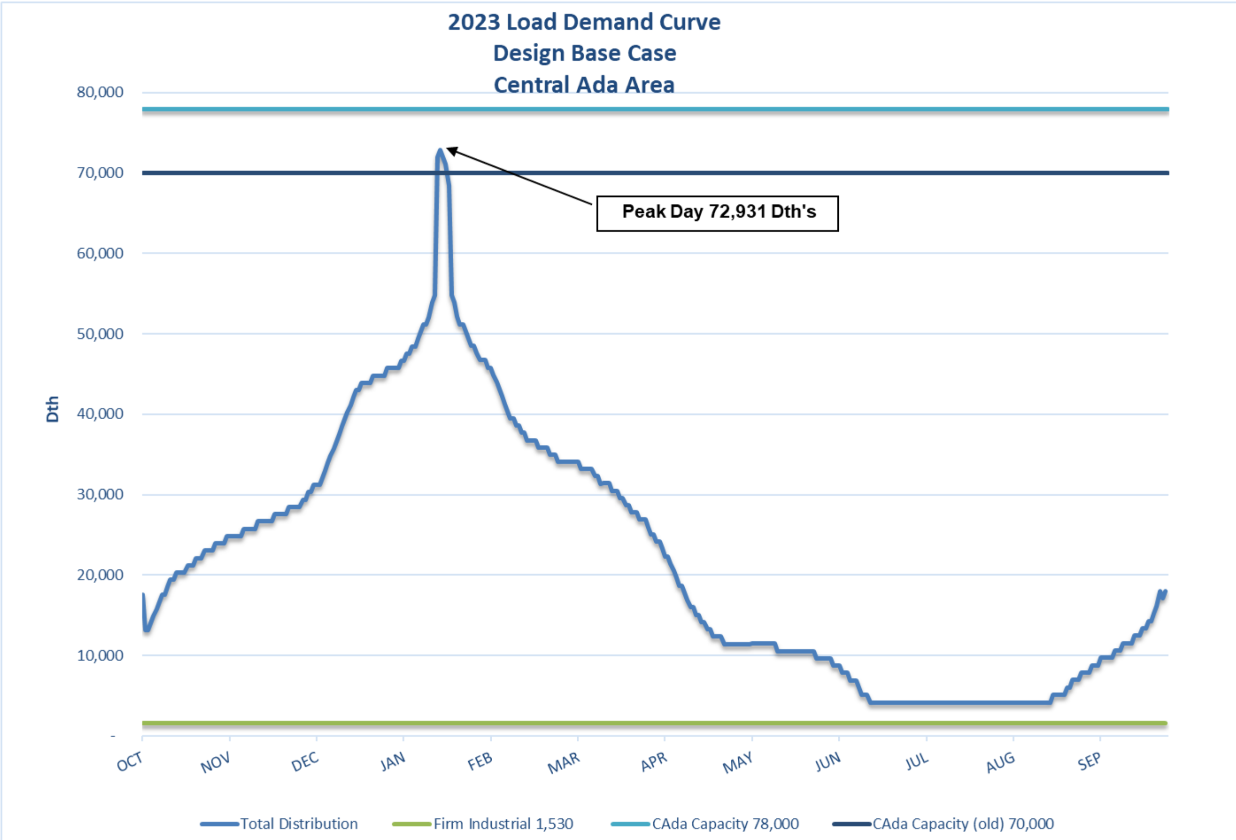


Central Ada County

Central Ada County is the newest AOI that consists of high pressure, intermediate pressure and distribution pressure systems in an area of Ada County that has historically experienced high levels of growth and development. The system currently has high pressure supplied from Chinden Boulevard on the north side of the defined area and high pressure supplied from Victory Road on the south side of the defined area. Initially the continued growth demands between these two separate systems taxed the Chinden high pressure pipeline and the branch lines supplied from Chinden. In 2016 an eight-inch pipeline was installed on Cloverdale Road that connected the Victory system to a branch of the Chinden system which alleviated the excess demand supplied from the Chinden pipeline. The connection between the two systems is an initial step in the long-term plan, and while the project successfully increased capacity in the area, the two systems are operating at different pressures and are currently disconnected through system valving.

With continued updates and monitoring of the Central Ada County AOI since the 2016 enhancement, continued growth has initiated the next planning step within the five-year outlook. Similar to State Street, the existing, large diameter pipeline on Victory Road has the potential for a pipeline retest that will increase its operating pressure and resulting flow capacity. This increase in operating pressure is designed to match the Chinden and Cloverdale operating pressure, and the retest is an initial step to create a consistent, connected system between the pipelines. Phase one of the retest is currently scheduled for completion in 2021. The retest begins at the Meridian gate station and extends approximately 2.5 miles.

The graph below shows no deficit with the proposed capacity under the base case scenario.

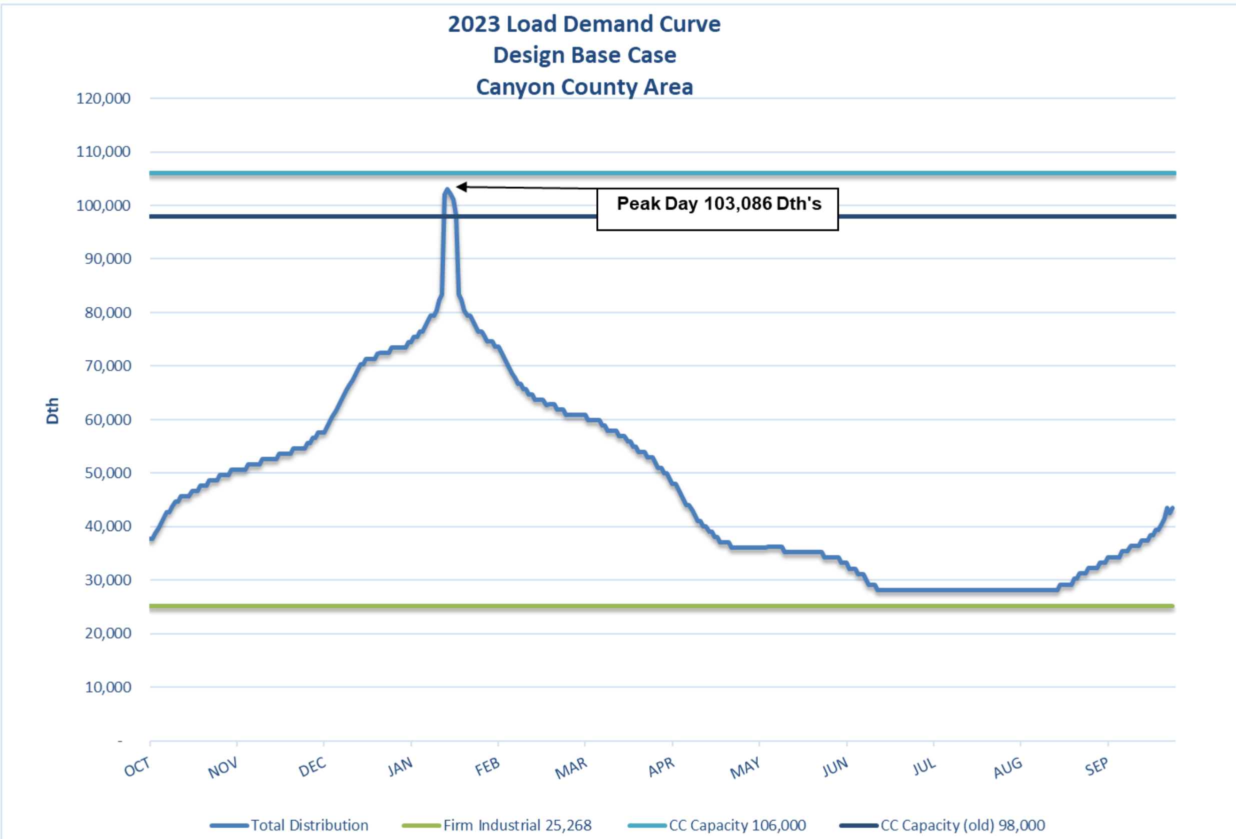


Canyon County

The Canyon County AOI consists of an interconnected system of high-pressure pipelines that serve communities from Star Road west to Highway 95. The system, originally serving Nampa and Caldwell, has continually extended west to additional towns and industrial customers. In 2013, the Canyon County system was connected to, and back-fed from, a new pipeline installed to the town of Parma. This Parma Lateral six-inch pipeline project provides a secondary feed to the Canyon County area. The next large system enhancement occurred in 2018 with the twelve-inch Ustick Caldwell pipeline project installed on the east side of Caldwell, which was required to remove pipeline flow restrictions through a bottleneck area.

For the outlook of this IRP, there are three enhancement projects required to meet projected growth demands throughout Canyon County. First is the 6-inch Orchard Avenue Extension project, which is planned for completion in 2020 and extends 4.5 miles into a significant growth area that is not currently supported by a nearby high-pressure pipeline. The Orchard Avenue Extension is location specific and not a direct benefit to the entire Canyon County AOI. Next is the second phase of the 12-inch Ustick Caldwell enhancement, extending the existing 2018 pipeline an additional 2 miles to the east. The 12-inch Ustick Caldwell project has a planned completion date of 2021 and is a benefit for the entire high-pressure system in Canyon County, continuing to eliminate bottlenecks in the overall system. Last is the 8-inch Happy Valley enhancement which extends high pressure pipeline 2 miles further into south Nampa. The 8-inch Happy Valley enhancement is currently planned for construction in 2022. This project is, again, designed as a location specific enhancement to accommodate specific growth and not directly related to the overall Canyon County AOI capacity.

The graph below shows no deficit with the proposed capacity under the base case scenario.

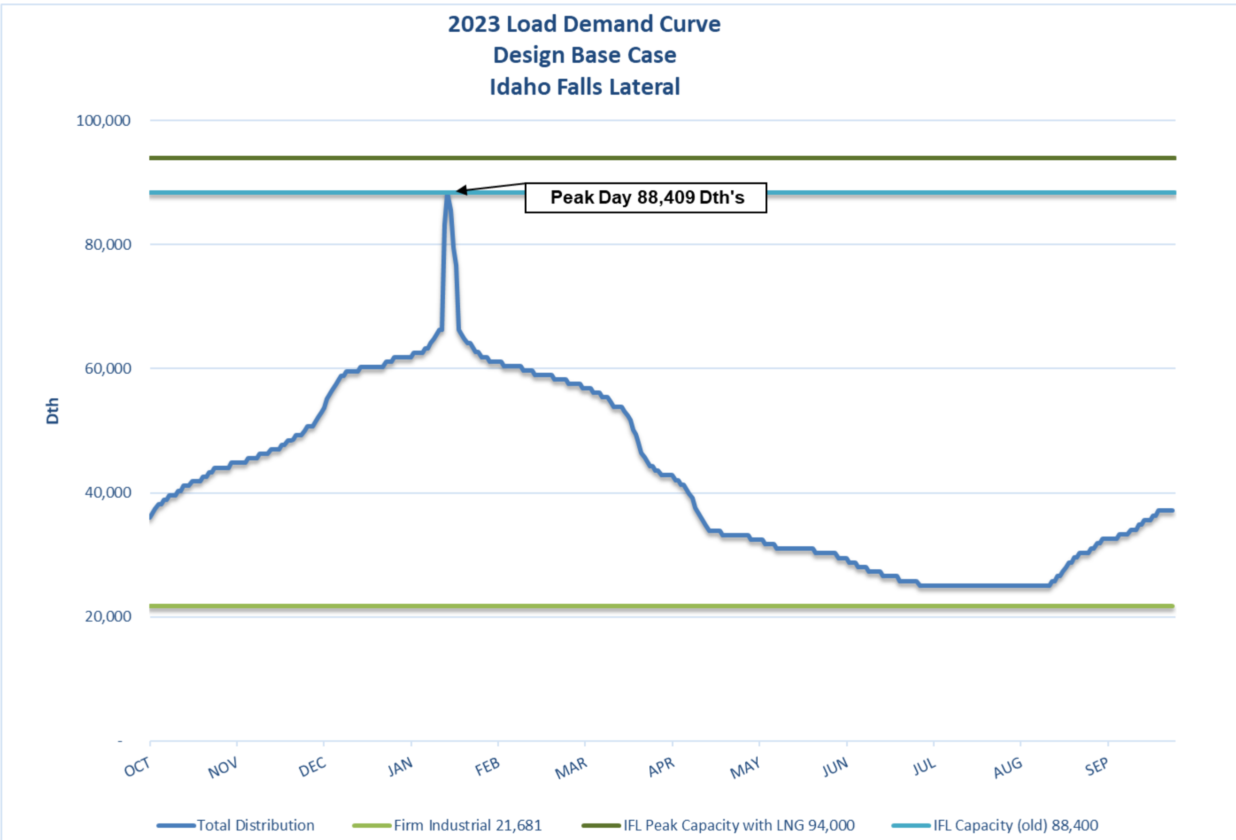


Idaho Falls Lateral

The Idaho Falls Lateral began as a 52-mile, ten-inch pipeline that originated just south of Pocatello and ended at the city of Idaho Falls. The IFL was later expanded farther to the north extending an additional 52 miles with 8-inch pipe to serve the growing towns of Rigby, Lewisville, Rexburg, Sugar City and Saint Anthony. As demand has continually increased along the IFL, Intermountain has been completing capacity enhancements for the past 25 years; including, compression (now retired), a satellite LNG facility, 40 miles of 12-inch pipeline loop, and 34.5 miles of 16-inch pipeline loop.

In 2012, Intermountain completed the addition of Phase V, a project that extended 15.5 miles of 16-inch high pressure pipeline to the north of Idaho Falls and increased the year-round capacity available on the lateral. With the addition of Phase V, and, utilizing the peak shaving benefits of the Rexburg LNG Facility, Intermountain has the capacity to serve the IFL for the next five years. Included as an IFL capacity enhancement within this IRP period is the addition of a second LNG storage tank at the Rexburg LNG Facility in 2022. The second tank will increase total available storage at the facility, which is desired as potential vaporization flow requirements increase out of the facility.

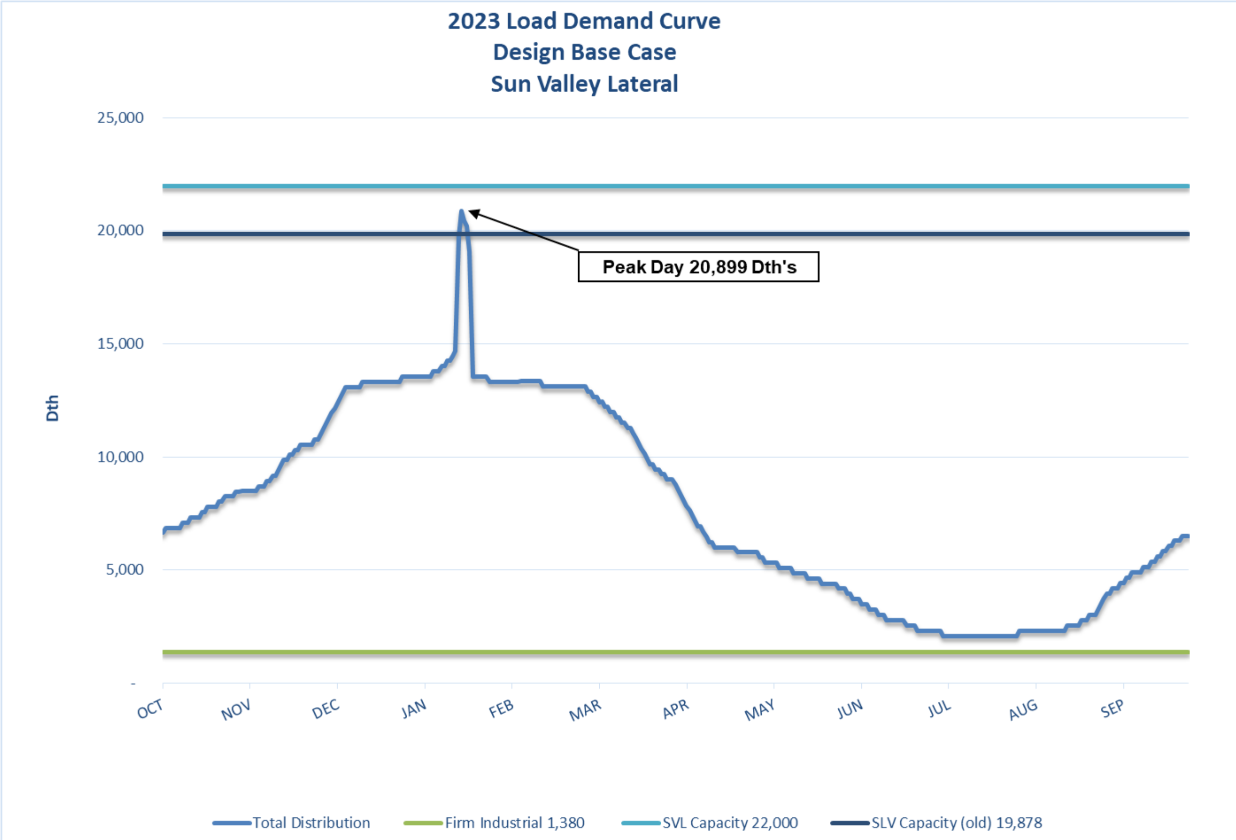
The graph below shows no deficit with the proposed capacity under the base case scenario.



Sun Valley Lateral

The Sun Valley Lateral is a 68-mile long, 8-inch high pressure pipeline that has almost its entire demand at the far end of the lateral away from the source of gas. Obtaining land in close proximity to this customer load center is either expensive or simply unobtainable. In addition, long sections of the pipeline are installed in rock that impose construction obstacles. Throughout the years Intermountain has uprated and upgraded this existing lateral, and most recently installed the Jerome Compressor Station towards the south end of the lateral in order to maintain capacity and increase flow toward the north end of the system. With continued demand growth, a second compressor station has been selected for enhancement of the SVL further downstream from the existing Jerome Compressor. This second station is scheduled for completion in 2021 and will increase capacity beyond the remaining five-year growth outlook of this IRP.

The graph below shows no deficit with the proposed capacity under the base case scenario.



2019 IRP vs. 2017 IRP Common Year Comparisons

This section compares any firm delivery deficits for Total Company and each AOI during the three common years of the 2019 and 2017 IRP filings.

Total Company Peak Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

2017 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

2019 IRP FIRM DELIVERY DEFICIT – TC DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of interstate capacity less total "peaking" storage. Peaking storage does not require the use of Intermountain's traditional interstate capacity to deliver inventory to the citygate.

Idaho Falls Lateral Peak Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE (Dth)	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – IFL DESIGN BASE CASE Over/(Under) 2017 (Dth)	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Sun Valley Lateral Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE (Dth)	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – SVL DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Canyon County Area Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – CCA DESIGN BASE CASE Over/(Under) 2017 (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

State Street Lateral Firm Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – SSL DESIGN BASE CASE Over/(Under) 2017 (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Central Ada County Firm Delivery Deficit Comparison

2019 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE (Dth)			
	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2017 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

2019 IRP FIRM DELIVERY DEFICIT – CAC DESIGN BASE CASE Over/(Under) 2017 (Dth)

	2019	2020	2021
Peak Day Deficit	0	0	0
Total Winter Deficit[1]	0	0	0
Days Requiring Additional Resources	0	0	0

[1]Equal to the total winter sendout in excess of distribution capacity.

Non-Utility LNG Forecast

Introduction

Since 1974, Intermountain has operated its Nampa Liquid Natural Gas (LNG) facility as a winter peaking supply source. The plant is designed to liquefy natural gas into LNG, store it in an onsite tank and vaporize it for injection into the Company's distribution system. The plant design includes a 50,000 gallon per day liquefaction train, a seven million-gallon storage tank and two water-bath vaporization units. The Nampa facility is utilized as the top of the Company's supply stack, or in other words, the last supply source that is used in the event of very cold weather or extraordinary system constraints.

In 2012 Intermountain began an efficiency review that focused on how it might better utilize its Nampa asset. Utilizing the then current IRP forecast, Intermountain determined how many gallons were projected to be withdrawn each winter season. That analysis showed that even under design weather assumptions, an excess of LNG supply would likely be available in each winter season.

Concurrent with the efficiency study, Intermountain began a study to determine the status of the regional LNG supply market relative to providing LNG to the Company's remote LNG facility near Rexburg, Idaho. Intermountain contacted several producing and marketing entities in the area who were then engaged in the non-utility LNG business to gauge future supply as well as the potential to enter the market as a supplier of LNG. It was discovered that due to already existing firm commitment during the heating season, it would be difficult to guarantee that an LNG supply would be available to Intermountain's Rexburg facility during the peak winter months.

History

LNG is a clean burning fuel that has the advantages of easy storage and transport under the right conditions. The two biggest markets for regional LNG are trucking fleets and remote-site heat and/or power applications. Though in relative infancy in the United States – particularly in the Pacific Northwest – LNG from a global perspective has a longer track record and continues to be in high demand in energy import areas like Asia.

As a direct result of the LNG supply study, Intermountain received an emergency supply request in late January 2013 to supply LNG to a small LNG-based distribution utility located in southwestern Wyoming that temporarily had lost its supply of LNG. The Idaho Public Utilities Commission (Commission) immediately granted emergency authority for Intermountain to supply the needed LNG pursuant to Case No. INT-G-13-01. Based on the efficiency review, the market study and the experience gained from supplying the emergency LNG, the Company filed Case No. INT-G-13-02 to request on-going authority from the Commission to sell "excess" LNG to non-utility customers.

Method of Forecasting

Intermountain utilized the results of the supply study (see Load Demand Curves starting on page 90) in this IRP to determine how much Nampa LNG would be needed for the core market during each year under the design weather/high growth scenario. To determine the annual amount of "excess" LNG, Intermountain adds to that annual core market withdrawal volume 1.2 million gallons of annual boiloff gas (which naturally occurs with the warming of LNG), 300,000 gallons to maintain operational and training requirements at the Nampa and Rexburg LNG facilities, and 500,000 gallons of "permanent" inventory to ensure that all LNG does not boiloff. After summing those potential needs for each year, the remaining capacity is assumed to be available for non-utility LNG sales customers. The table below shows the annual amount of Nampa LNG assumed to be available for non-utility sales over the IRP. For planning purposes, Intermountain will not allow the tank inventory level to drop below the Net Utility Requirements shown below at any time during December – February of any year since this is the peak demand season for the Company's distribution system. Further, should the need arise, all volumes are always available to serve the core market. It should be noted that the amount shown as "Available for Non-utility Sales" is a point-in-time figure.

Table 16: Nampa LNG Inventory Available for Non-Utility Sales

Nampa LNG Inventory Available for Non-Utility Sales					
Gallons	2019	2020	2021	2022	2023
Projected Withdrawal (High Growth)	0	0	21,417	101,928	195,055
Maximum Day Withdrawal	0	0	17,216	40,498	64,534
Annual Boil-off	1,200,000	1,200,000	1,200,000	1,200,000	1,200,000
Permanent Inventory	500,000	500,000	500,000	500,000	500,000
Nampa & Rexburg Requirements	300,000	300,000	300,000	300,000	300,000
Net Utility Requirement	2,000,000	2,000,000	2,021,417	2,101,928	2,195,055
Available for Non-utility Sales	5,000,000	5,000,000	4,978,583	4,898,072	4,804,945

Benefits to Customers

Intermountain's customers benefit from Intermountain's LNG sales activities in several different ways. First, Intermountain continues to defer 2.5¢ per gallon sold into a capital account and utilizes that balance as it identifies capital costs that were accelerated due to increased use of the Nampa LNG facility. That procedure directly reduces both rate base and depreciation expense. Intermountain also continues to pass back to customers in its annual Purchased Gas Adjustment filing (PGA) a credit of 2.5¢ per gallon sold as an offset to increased operating and maintenance costs as a result of non-utility sales. Finally, Intermountain's customers also benefit from the current 50/50 margin sharing mechanism which offsets gas purchase costs in the Company's annual PGA.

Since April 2013, Intermountain has sold nearly 20 million gallons of non-utility LNG. These sales have provided nearly $500,000 to offset increased capital costs. Additionally, the Company has passed back through its PGA approximately $500,000 to offset increased O&M costs as well as over $2.5 million from the margin sharing mechanism. The PGA passback has reduced Intermountain's gas costs every year since October 2013.

Another benefit comes from the fact that the Company has been selling much of its LNG to markets which utilize it in Idaho. Much of the market relates to trucks that formerly burned diesel as a fuel. LNG sales have increased economic growth in the state and have also provided cleaner air benefits. The markets Intermountain sells LNG to have expressed appreciation for a local, reliable, competitively priced fuel. In fact, they have gone so far as to suggest that if the Nampa facility was no longer able to supply non-utility LNG, it would leave a hole in the fuel market that would be difficult, if not impossible, to fill. Further, many of the truck drivers have expressed a preference to load at Nampa as the design and operations allow for more convenient and quicker trailer fills.

On-Going Challenges

Since one of the biggest potential target markets for Intermountain is "big rig" diesel fuel replacement, the relatively low retail diesel prices over the past several years has stunted the growth in the LNG trucking market. Low diesel prices tighten the cost differential between diesel and LNG and consequently the Company has had little ability to increase sales prices.

A further challenge has been the lack of available large displacement LNG engines. Because of the frequency and magnitude of roadway inclines, the mountain west trucking industry prefers to rely on 15-liter engines. However, manufacturers do not produce a 15-liter LNG engine, resulting in a challenge to utilize natural gas-powered engines to haul the heaviest loads. Thus, lower diesel prices combined with the lack of a 15-liter, LNG-powered engine has hampered growth in LNG sales demand. These challenges have limited revenue growth in Intermountain's non-utility LNG sales.

The good news is that continuing efforts to work with existing LNG markets while also marketing to new entities has resulted in Intermountain growing its sales every year since 2013. Further, Intermountain continues to improve its management of LNG inventory cost which has helped to support average sales margins.

Safeguards

As described above, Intermountain takes steps to ensure that it maintains enough LNG in the tank to provide for all projected customer withdrawal needs. This insulates the core market from the risk of having no LNG should the need for needle peak withdrawals arise. Intermountain has also committed to the Commission that all volumes in the tank, regardless of the intended market, would always be available to serve the core market should the need arise. Additionally, while the Company shares LNG margins with its customers through the PGA, it also insulates its end-use customers from any risk of loss due to non-utility sales.

Future

Intermountain continues to see growth in non-utility LNG sales and may even reach a point where annual liquefaction levels are maximized. As the market continues to look for ways to satisfy ever more stringent emissions standards, it is believed that LNG will generate more interest. Looking to the future, most forecasts predict a continuation of low oil and natural gas prices leading the Company to expect somewhat flat sales margins but steady growth in LNG sales.

One advantage the Company has is the ability to store large amounts of LNG which would last for an extended period of time for vaporization purposes. Because of its storage capability, some markets look to Nampa as a backstop supplier when other facilities might experience outages or planned downtime. Should the non-utility sales market continue to show strong growth, the Company would likely not need more storage capacity, but could address the need for more day-to-day sales volumes by adding to or upgrading its liquefaction train in order to increase the daily production of LNG.

The biggest disadvantage of the Nampa plant relates to the cost of liquefaction. Stand-alone commercial LNG production facilities do not need large storage tanks, vaporizers or other equipment designed to support peak shaving withdrawals and can therefore operate at a lower cost. In addition, newer facilities utilize more recent technology that can simply liquefy more efficiently than older facilities. A potential risk to Intermountain's LNG sales would be the construction of new commercial LNG facilities in the region that would have lower operating costs which could result in the loss of customers currently served by the Nampa facility or lower sales margins.

Recommendation

Challenges relating to growth in sales volumes and a market facing flat margins growth remain. A longer-term increase in diesel prices would provide more opportunity to grow both non-utility LNG sales and margins. Intermountain's Nampa LNG facility is located in an area without direct competitors and the Company continues to build brand loyalty. Based on the benefits to Intermountain and its utility customers, the lack of risk to its customers and the ability to make more efficient use of the Nampa LNG assets, Intermountain recommends that the Commission continue to allow Intermountain to sell excess LNG to non-utility customers.

Infrastructure Replacement

Intermountain Gas Company is committed to providing safe and reliable natural gas service to its customers. As part of this commitment, Intermountain proactively monitors its pipeline system utilizing risk management tools and engineering analysis. Additionally, the Company adheres to federal, state and local requirements to replace or improve pipelines and infrastructure as required. Infrastructure that is identified as a potential risk is reviewed and prioritized for replacement or risk mitigation.

As part of the IRP process, Intermountain will address two significant infrastructure replacement projects scheduled to occur within the IRP outlook. These replacement projects are not growth driven.

Rexburg Snake River Crossing

The Rexburg Snake River crossing is an eight-inch steel transmission pipeline installed under the Snake River southwest of Rexburg, ID which has been identified as an infrastructure replacement project, tentatively scheduled for planning year 2021. The pipeline was identified for replacement due to risks related to the Snake River and surrounding flood plain. The location of the pipeline under the Snake River and perpendicular to the river along its east bank leave the pipeline susceptible to loss of adequate cover should the river's rate of flow increase to the point of spilling over the existing bank and/or scouring the existing river bottom.

The Rexburg Snake River crossing has been monitored and has required occasional attention. The riverbank has been rebuilt and reinforced by Intermountain to prevent undermining of the bank and reduce the potential to flood, and the Company has installed engineered scour protection measures over the top of the pipeline to prevent cover loss within the river. These efforts have been successful to date; although, due to the ongoing monitor and mitigation efforts, along with the ever-present risks associated with this scenario, the Company plans to replace the existing pipeline.

Intermountain's selected replacement method for this existing river crossing is to utilize horizontal directional drilling technology to install a new pipeline much further below the river bottom and surrounding flood area. Horizontal directional drilling will allow the pipeline to be installed much deeper in the ground than conventional installation practices and will avoid any disturbance to the Snake River and the sensitive land surrounding the river. The significant increase in pipeline depth will mitigate the existing risk.

Aldyl-A Pipe Replacement

Intermountain has created an Integrity Management Program to proactively identify, analyze and monitor any risk related to the pipeline system, and to create programs that will reduce or remove those risks. In order to identify risks on the system, the Company utilizes a risk model to manage and assess the risk of infrastructure based on age, material, operating pressure and damage history, as well as other considerations. The model is then used to prioritize mitigation efforts, and infrastructure replacement projects are created as a result. Aldyl-A pipe replacement was identified as a priority from the risk model and has become a substantial, ongoing project.

Aldyl-A is a polyethylene material created by DuPont and used in the manufacturing of pipe and fittings. Aldyl-A pipe manufactured prior to 1984 is now known in the gas industry as being susceptible to loss of flexibility which can allow cracking under certain circumstances. Since 2013, Intermountain has actively replaced Aldyl-A plastic pipe within the distribution system and continues to replace approximately five miles of pipeline each year; prioritized by risk metrics that are renewed annually. The Aldyl-A replacement plan will continue through the duration of the IRP.

Glossary

Agent (Marketer)
A legal representative of buyers, sellers or shippers of natural gas in negotiation or operations of contractual agreements.

All Other Customers Segment (All Other)
All other segments of the Company's distribution system serving core market customers in Ada County not included in the State Street Lateral or Central Ada County, as well as customers in Bannock, Bear Lake, Caribou, Cassia, Elmore, Gem, Gooding, Jerome, Minidoka, Owyhee, Payette, Power, Twin Falls, and Washington counties; an Area of Interest for Intermountain.

Area of Interest (AOI)
Distinct segments within Intermountain's current distribution system.

British Thermal Unit (BTU)
The amount of heat that is necessary to raise the temperature of one pound of water by 1 degree Fahrenheit

Bundled Service
Gas sales service and transportation service packaged together in a single transaction in which the utility, on behalf of the customer, buys gas from producers and then transports and delivers it to the customer.

Canyon County Area (CCA)
A distinct segment of Intermountain's distribution system which serves core market customers in Canyon County; an Area of Interest for Intermountain.

Central Ada County (CAC)
Multiple high-pressure pipeline systems which serve core market customers in Ada County between Chinden Boulevard and Victory Road, north to south, and between Maple Grove Road and Black Cat Road, east to west; an Area of Interest for Intermountain.

Citygate
The points of delivery between the interstate pipelines providing service to the utility or the location(s) at which custody of gas passes from the pipeline to the utility.

Commercial
A customer that is neither a residential nor a contract/large volume customer whose requirements for natural gas service do not exceed 2,000 therms per day. These customers are typically commercial businesses or small manufacturing facilities.

Contract Demand (CD)
The maximum peak day amount of distribution capacity that Intermountain guarantees to reserve for a firm customer each day. The amount is specified in the customer contract. Also see MDFQ.

Core Market
All residential and commercial customers of Intermountain Gas Company. Includes all customers receiving service under the RS and GS tariffs.

Customer Management Module (CMM)
A software product, provided by DNV GL as part of their Synergi Gas product line, to analyze natural gas usage data and predict usage patterns on an individual customer level.

Delivery (Receipt Point)
Designated points where natural gas is transferred from one party to another. Receipt points are those locations where a local distribution company delivers, and an interstate pipeline receives, gas supplies for re-delivery to the local distribution company's city gates.

Design Year
An estimate of the highest level of annual customer demand that may occur, incorporating extreme cold or peak weather events; a measure used for planning capacity requirements.

Design Weather
Heating degree days that represent the coldest temperatures that may occur in the IGC service territory.

Direct Use
The use of natural gas at the point of final heating energy use, such as natural gas space heating, water heating, cooking, and other heating uses, as opposed to burning natural gas in a power plant to generate electricity to be used at the point(s) of use to for site space heat, water heat, cooking heat and other heat applications. Direct use is a much more efficient use of natural gas.

Demand Side Management (DSM)
Programs implemented by the Company and utilized by its customers to influence the amount and timing of natural gas consumption.

Electronic Bulletin Board (EBB)
A generic name for the system of electronic posting of pipeline transmission information as mandated by FERC.

FERC - Federal Energy Regulatory Commission
The federal agency that regulates interstate gas pipelines and interstate gas sales under the Natural Gas Act. Successor to the Federal Power Commission, the FERC is considered an independent regulatory agency responsible primarily to Congress, but it is housed in the Department of Energy.

Firm Customer
A customer receiving service under rate schedules or contracts designed to provide the customer's gas supply and distribution needs on a continuous basis, even on a peak day.

Firm Service
A service offered to customers under schedules or contracts which anticipate no interruptions.

Fixed Physical
A fixed forward (also known as a fixed price physical contract) is an agreement between two parties to buy or sell a specified amount of natural gas at a certain future time, at a specific price, which is agreed upon at the time the deal is executed. It operates much like the price swap without the margin call risk.

Formation
A formation refers to either a certain layer of the earth's crust, or a certain area of a layer. It often refers to the area of rock where a petroleum or other hydrocarbon reservoir is located. Other related terms are basin or play.

Gas Transmission Northwest (GTN)
A U.S. pipeline which begins at the U.S.-Canadian border near Kingsgate, British Columbia and interconnects with Williams Northwest Pipeline at the Stanfield receipt point in Oregon.

Heating Degree Day (HDD)
An industry-wide standard, measuring how cold the weather is based on the extent to which the daily mean temperature falls below a reference temperature base, which for IGC, is 65 degrees Fahrenheit.

Horizontal Directional Drilling
Heralded as causing the greatest change in the industry since the invention of the rotary bit, horizontal drilling utilizes special equipment that allows well drillers to extend horizontal shafts from one vertical shaft into areas that could not otherwise be reached. This technique is especially useful in offshore drilling, where one platform may service many horizontal shafts, thus increasing efficiency. Horizontal wells can be extended from as short as 20-40ft from vertical to as long as 1,000-4,500ft from the vertical radius.

Idaho Falls Lateral (IFL)
A distinct segment of Intermountain's distribution system which serves core market customers in Bingham, Bonneville, Fremont, Jefferson, and Madison counties; an Area of Interest for Intermountain.

Industrial Customer
For purposes of categorizing large volume customers, any customer utilizing natural gas for vegetable, feedstock or chemical production, equipment fabrication and/or manufacturing or heating load for production purposes.

Institutional Customer
For purposes of categorizing large volume customers, this would include business such as hospitals, schools, and other weather sensitive customers.

Interruptible Customer
A customer receiving service under rate schedules or contracts which permit interruption of service on short notice due to insufficient gas supply or capacity.

Interruptible Service
Lower-priority service offered to customers under schedules or contracts which anticipate and permit interruption on short notice, generally in peak-load seasons, by reason of the higher priority claim of firm service customers and other higher priority users. Service is available at any time of the year if distribution capacity and/or pressure is sufficient.

Large Volume Customer
Any customer receiving service under one of the Company's large volume tariffs including LV-1, T-3, and T-4. Such service requires the customer to sign a minimum one-year contract and use at least 200,000 therms per contract year.

Liquefied Natural Gas (LNG)
Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure. In volume, it occupies one-six-hundredth of that of the vapor at standard conditions.

Load Demand Curve (LDC)
A forecast of daily gas demand using design or normal temperatures, and predetermined usage per customer.

Local Distribution Company
A retail gas distribution company, utility, that delivers retail natural gas to end users.

Lost and Unaccounted for Natural Gas (LAUF)
The difference between volumes of natural gas delivered to Intermountain's distribution system and volumes of natural gas billed to Intermountain's customers.

Maximum Daily Firm Quantity (MDFQ)
The contractual amount that Intermountain guarantees to deliver to the customer each day. Also see Contract Demand.

Methane
Methane is commonly known as natural gas (or CH_4) and is the most common of the hydrocarbon gases. It is colorless and naturally odorless and burns efficiently without many by products. Natural gas only has an odor when it enters a customer's home because the local distributor adds it as a safety measure.

Normal Weather
Normal weather is comprised of HDD's that represent the average mean temperature for each day of the year. Intermountain's Normal Weather is a 30-year rolling average of NOAA's daily mean temperature.

Northwest Pipeline (Williams Northwest Pipeline, Northwest, NWP)
A 3,900-mile, bi-directional transmission pipeline crossing the states of Washington, Oregon, Idaho, Wyoming, Utah and Colorado and the only interstate pipeline which interconnects to Intermountain's distribution system; all gas supply received by the Company is transported by this pipeline.

NYMEX Futures
New York Mercantile Exchange is the world's largest physical commodity futures exchange. Futures are financial contracts obligating the buyer to purchase an asset (or the seller to sell an asset), such as a physical commodity, at a predetermined future date and price. Futures contracts detail the quality and quantity of the underlying asset; they are standardized to facilitate trading on a futures exchange. Some futures contracts may call for physical delivery of the asset, while others are settled in cash.

Peak Shaving
Using sources of energy, such as natural gas from storage, to supplement the normal amounts delivered to customers during peak-use periods. Using these supplemental sources prevents pipelines from having to expand their delivery facilities just to accommodate short periods of extremely high demand.

Peak Day

The coldest day of the design year; a measure used for planning system capacity requirements. For Intermountain, that day is currently January 15 of the design year.

PSIG (Pounds per Square Inch Gauge)
Pressure measured with respect to that of the atmosphere. This is a pressure gauge reading in which the gauge is adjusted to read zero at the surrounding atmospheric pressure. It is commonly called gauge pressure.

Producer
A natural gas producer is generally involved in exploration, drilling, and refinement of natural gas. There are independent producers, as well as integrated producers, which are generally larger companies that produce, transport and distribute natural gas.

Purchased Gas Adjustment or PGA
Intermountain's annual price change to adjust the cost of gas service to its customers, based on deferrals from the prior year and forward-looking cost forecasts.

Residential Customer
Any customer receiving service under the Company's RS Rate Schedule.

SCADA (Supervisory Control and Data Acquisition)
Remote controlled equipment used by pipelines and utilities to operate their gas systems. These computerized networks can acquire immediate data concerning flow, pressure or volumes of gas, as well as control different aspects of gas transmission throughout a pipeline system.

State Street Lateral (SSL)
A distinct segment of Intermountain's distribution system which serves core market customers in Ada County north of the Boise River, bound on the west by Kingsbury Road west of Star, and bound on the east by State Highway 21; an Area of Interest for Intermountain.

Sun Valley Lateral (SVL)
A distinct segment of Intermountain's distribution system that serves customers in Blaine and Lincoln counties; an Area of Interest for Intermountain.

Therm

A unit of heat energy equal to 100,000 British thermal units (BTU). It is approximately the energy equivalent of burning 100 cubic feet (1 CCF) of natural gas.

Traffic Analysis Zones (TAZ)
An analysis of traffic patterns in certain high traffic areas.

Transportation Tariff

Tariffs that provide for the redelivery of a shipper's natural gas received into an interstate pipeline or Intermountain's distribution system. A transportation customer is responsible for procuring its own supply of natural gas and transporting it on the interstate pipeline system for delivery to Intermountain at one of its citygate locations.

WCSB (Western Canadian Sedimentary Basin)

A vast sedimentary basin underlying 1,400,000 square kilometers (540,000 sq mi) of Western Canada including southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories. It consists of a massive wedge of sedimentary rock extending from the Rocky Mountains in the west to the Canadian Shield in the east. The WCSB contains one of the world's largest reserves of petroleum and natural gas and supplies producing more than 16,000,000,000 cubic feet (450,000,000 m3) per day of gas in 2000.