# DEMAND FORECAST
## CHAPTER FIVE

PUGET SOUND ENERGY

# Contents

1. Introduction .... 1
   1.1. Impacts of Demand-side Resources .... 2
2. Climate Change .... 3
   2.1. Priorities First .... 3
   2.2. Determine Normal Temperatures .... 4
   2.3. Normal Temperature for Energy Demand Forecast .... 5
   2.4. Design Temperature for Peak Demand Forecast .... 6
3. Gas Demand Forecast .... 7
   3.1. Gas Energy Demand .... 7
   3.2. Gas Peak Demand .... 9
   3.3. Impacts of Demand-side Resources Illustrated .... 11
   3.4. Details of the Gas Forecast .... 13
4. Methodology .... 14
   4.1. Forecasting Process .... 14
   4.2. Zero-customer Growth Scenario .... 16
   4.3. Stochastics .... 16
   4.4. Updates to Inputs and Equations .... 16
5. Key Assumptions .... 17
   5.1. Economic Growth .... 17
   5.2. National Economic Outlook .... 17
   5.3. Population Outlook .... 18
   5.4. Regional Economic Outlook .... 18
   5.5. Gas Service Area Outlook .... 18
   5.6. Weather .... 19
   5.7. COVID-19 Impacts .... 19
   5.8. Gas Decarbonization .... 20
   5.9. Loss Factors .... 20
   5.10. Block Load Additions .... 20
   5.11. Transport Customers .... 20
   5.12. Interruptible Loads .... 20
   5.13. Compressed Gas Vehicles .... 21
   5.14. Retail Rates .... 21
6. Previous Demand Forecasts .... 21
   6.1. Peak Demand Forecasts Compared to Actual Peaks .... 21

6.2. Reasons for Forecast Variance ..........23

# 1. Introduction

Puget Sound Energy (PSE) developed demand forecasts for the 2023 Gas Utility Integrated Resource Plan (2023 Gas Utility IRP) to estimate the amount of gas required to meet customer needs from 2024 to 2050. These forecasts focus on two dimensions of demand: energy demand and peak demand.

- Energy demand is the total amount of gas needed to meet customer needs in a year.
- Peak demand is the amount of gas needed to serve customer needs on the coldest day of the year.

Climate change already affects how our customers use energy, and we anticipate that impact will increase. We expect summer and winter average temperatures to get warmer. This report's energy and peak demand forecasts incorporate climate change temperature effects for the first time. Our customers, indeed, all of us, feel the impact of climate change every day, and this data is a crucial component of our energy planning.

This IRP base demand forecast is the expected outcome before we apply additional demand-side resources (DSR). The 2023 base energy demand forecast is lower than the 2021 IRP base demand forecast because this IRP includes the temperature effects of climate change on demand. The 2021 IRP did not consider the impacts of climate change, which lower energy demand considerably.

Although climate change is expected to increase temperatures on average, the extreme low temperature that we need to plan for remains consistent at 13°F. Therefore, this IRP peak demand is very similar to the 2021 IRP peak demand because the design peak temperature did not change between the two forecasts.

**Climate Change**

We incorporated climate change into the demand forecast for the first time in this 2023 Gas Utility IRP. We heard from interested parties that addressing climate change is critical and we agree. We also know climate change will affect future demand and needs. The team included climate change in the base demand forecast and in other analyses such as the stochastic scenarios.

Table 5.1: Drivers Included and Not Included in the Base Demand Forecasts

| Drivers | Demand Forecast Before Additional DSR | Demand Forecast After Additional DSR |
|---|---|---|
| Climate change temperatures | Yes | Yes |
| PSE energy efficiency programs for 2022–2023 | Yes | Yes |
| Codes and standards effects through 2023, including Seattle gas ban | Yes | Yes |
| PSE energy efficiency programs for 2024 and beyond | No | Yes |
| Codes and standards for 2024 and beyond including Seattle and Shoreline gas bans | No | Yes |
| Additional electrification | No | Note: To be analyzed with scenarios |
| Effects of the Climate Commitment Act | No | Yes |
| Effects of the Inflation Reduction Act | No | No |

We also prepared a zero-customer growth scenario with no new customer growth after 2026. This analysis created a slightly declining energy demand forecast and an almost flat design peak forecast. We used this scenario to project future demand with less gas in PSE's service area. As noted in Table 5.1, we created the demand forecast before we were able to incorporate the impacts of the Inflation Reduction Act (IRA). The IRA will likely lead to lower gas demand since it incentivizes the use of heat pumps. We will account for the IRA's impacts in future demand forecasts.

## 1.1. Impacts of Demand-side Resources

We saw a significant demand reduction when we applied forward projections of additional DSR savings, as shown in Table 5.2. However, we must start with forecasts that do not include forward projections of DSR savings to identify the most cost-effective amount of DSR to include in the resource plan.

Throughout this chapter, charts labeled before additional DSR reflect only DSR measures and regional effects from policies that limit the use of natural gas before the study period begins in 2024. These charts do not reflect Climate Commitment Act (CCA) effects. Charts labeled after additional DSR reflect the cost-effective amount of DSR identified in this IRP and the impacts of new codes and standards, including the effects of policies that limit the use of natural gas in 2024 and after, and additional DSR resulting from the CCA.

**Why does PSE forecast demand before DSR?**

The demand forecast before DSR shows us the projected demand assuming no resource actions are taken. This provides the demand that can be managed with demand-side resources and can be used to determine which actions are cost-effective resource decisions.

**What if no one acted to change how we use energy?**

We have already changed how we use energy, so this is not a future we anticipate. PSE expects to continue incentivizing DSR. Federal, state, and local governments will continue changing energy codes and standards, and we expect consumers to continue adopting heat pump technology. But how much of this will occur, and how will it change the demand forecast? To answer this question, we start with the assumption of no DSR and treat DSR as a resource in the modeling process.

Table 5.2: Effect of Demand-side Resources on Demand Forecasts

| 2023 Gas Utility IRP Zero-Customer Growth Forecast in 2050 | Before Additional DSR | After Additional DSR |
|---|---|---|
| Gas Energy Demand (MDth) | 86,816 | 70,348 |
| Gas Peak Demand (MDth) | 1,001 | 809 |

# 2. Climate Change

> **Climate Change**
>
> There are currently no industry standards or best practices for incorporating climate change into a demand forecast. Puget Sound Energy is excited to include climate change in this 2023 Gas Utility IRP and lead future refinements and the evolution of this methodology.

This IRP incorporates climate change in the base energy and peak demand forecast for the first time. Before this IRP, PSE used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This old approach was a common utility practice but does not recognize predicted climate change.

The methodology for incorporating climate change in this IRP is our first step, and we expect it will evolve. PSE is unaware of industry standards or best practices for integrating climate change into a demand forecast. This section provides a detailed description of how we developed a normal temperature assumption.

## 2.1. Priorities First

Puget Sound Energy heard and heeded the clear message from interested parties that climate change is a high priority, and we should incorporate its effects into our planning processes. It is essential to consider climate change in resource planning because temperature impacts the amount of heating fuel used throughout the year. Over time, we expect less overall heating demand because of a general average warming trend. We used regional data recently developed by climate change scientists to calculate a normal temperature assumption that reflects climate change.

We are incorporating climate change into the demand forecast in several ways:

- Energy demand forecast
- Peak demand forecast
- Stochastic analysis

The climate projections used in the forecast were part of a recent study conducted by the River Management Joint Operating Committee (RMJOC). The RMJOC consists of the Bonneville Power Administration, the U.S. Army Corps of Engineers, and the U.S. Bureau of Reclamation. This committee worked with climate scientists to produce many downscaled climate models and hydrologic models for the Northwest region as part of their long-term planning.[1] The RMJOC chose 19 downscaled models. Each model is on the representative concentration pathway (RCP) of 8.5. An RCP is a forecast of the amount of warming to the Earth. RCP 8.5 is a common warming forecast used by climate scientists. It represents more warming than other common warming forecasts, such as RCP 4.5 or RCP 6.0.

The Northwest Power and Conservation Council (NWPCC) then chose three of the 19 models to work with: CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA. The NWPCC chose these three models because they

[1] River Joint Management Operating Committee (RMJOC): Bonneville Power Administration, United State Army Corps of Engineers, United Stats Bureau of Reclamation (2018). Climate and Hydrology Datasets for RMJOC Long-Term Planning Studies: Second Edition (RMJOC-II) Part 1: Hydroclimate Projections and Analyses, https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/rmjoc-II-report-part-I.pdf.

reflect a wide range of temperatures and hydrologic conditions over time. PSE decided to use the three climate model projections that the NWPCC used.

## 2.2. Determine Normal Temperatures

Since there is no industry standard approach to integrating climate change, we had to determine how to incorporate this data into our forecasts. The following section explains how we approached the challenge and the questions we asked. We also presented these questions and the analysis results to the public on January 20, 2022, and asked them for feedback on our approach.

### 2.2.1. What Is Normal and Why We Need It

When PSE models demand, we study the relationship between historical demand and historical temperatures because the temperature significantly impacts demand. Then, to create a demand forecast, PSE must make assumptions about future temperatures to create a future demand forecast. We refer to the assumed future temperatures as normal temperatures. For energy forecasting, the average heating degree day (HDD) for a month expresses the new normal temperature. We used a 1-in-50 occurrence of a given temperature to forecast peak demand. Design peak examines daily loads under extreme cold weather conditions.

We wanted to achieve three goals when we created new normal temperatures:

1. Incorporate future temperature data into the assumptions for the base demand forecasts. We provided a scenario in the 2021 IRP with climate change temperatures but incorporated it into this report's base demand energy and the base demand peak forecasts.
2. Produce the demand forecast in the framework necessary for planning. Integrated Resource Plan analyses have specific input requirements. For example, we could have run the demand forecast with the climate data from the three models, but this would have created three base forecasts. Instead, we created one demand forecast because we need a single outcome as a reference case.
3. Develop an objective temperature normal, which includes deciding what data to use.

### 2.2.2. Which Data Do We Use?

We considered the following questions when we decided what data to use to define a new normal temperature:

1. **Should we use one climate model to predict future temperatures, or should we use all three models the NWPCC chose to create the new normal?**

   Since the three models the NWPCC used show a wide range of possible climate outcomes, we used all three to capture the broadest possible range of results.

2. **Should the forecasted new normal temperature include historical data, forecasted climate model data, or some combination of the two?**

   Recent historical data is a way to link climate change data to what has occurred recently in the region. For example, in 2021, PSE's service area saw unprecedented hot temperatures, including 107° F at Seattle-

Tacoma International Airport on June 28, 2021. However, the climate models did not predict a temperature this high until 2035. Incorporating recent actual data helped us determine where the forecast should start.

Based on this assessment, we used historical data and forecasted temperatures to calculate a new normal temperature.

3. **How many years of data should we include to calculate this new normal?**

   In past IRPs, we estimated the normal temperature using the last 30 years of temperatures to calculate the base energy demand forecast. This methodology created a relatively stable normal, with minor year-to-year changes. Forecasts that use five- or 10-year derived normal temperatures can have much larger swings in the normal data point from year to year, creating difficulties for planning. Therefore, we opted to use a 30-year analysis centered on the year of interest. We used forecast temperatures from the prior 15 and the upcoming 15 years for each year in the calculation. We calculated this for each year of the forecast.

4. **Should the forecasted new normal temperatures be flat, as used in past IRPs, or should the forecast reflect a trend?**

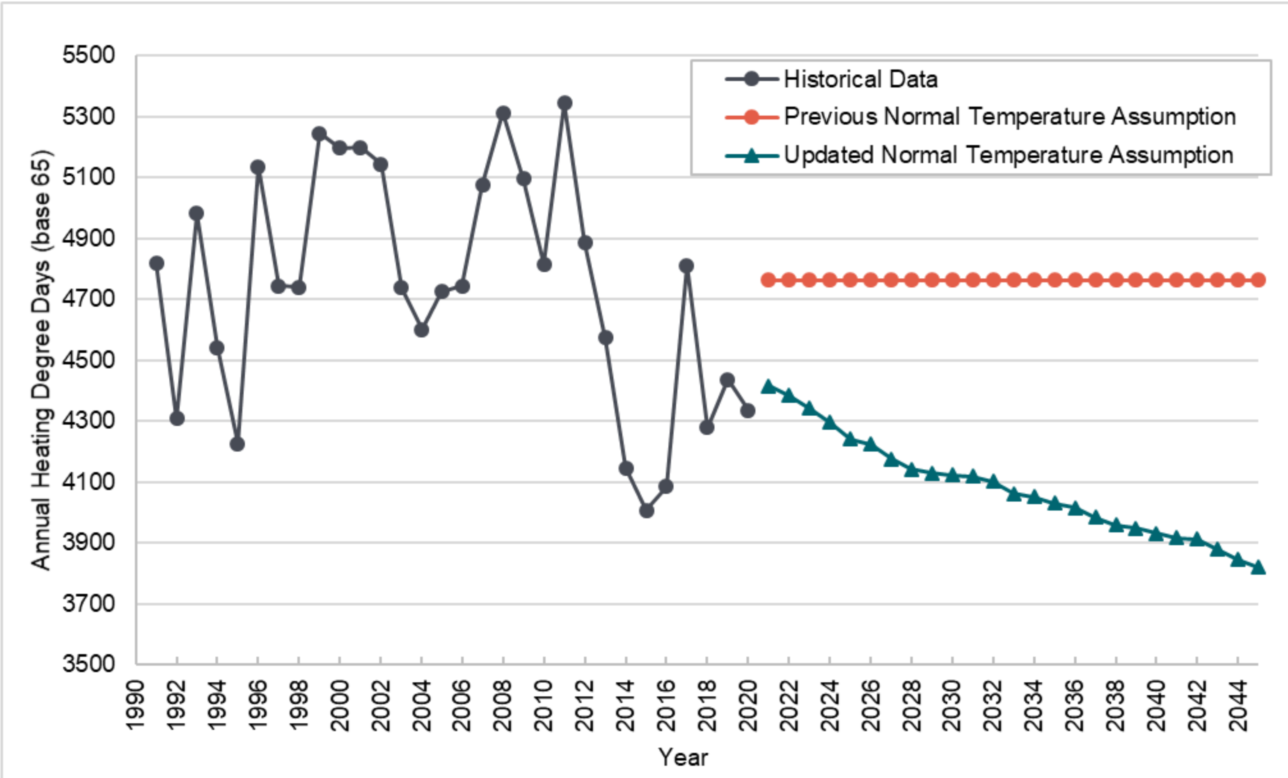
   We needed to reflect average temperatures warming over time, so the normal energy forecast reflected this with increasing average temperatures in the winter.

## 2.3. Normal Temperature for Energy Demand Forecast

We incorporated the normal temperatures into the base energy demand forecast models through heating degree days (HDDs). Heating degree days are a standard way to express temperatures to measure how much heating demand a customer may use in response to a given daily temperature. We calculate degree days using a base temperature, typically 65° F, and the average daily temperature. For HDDs, we calculate the value as the amount the daily temperature is below 65° F. For example, a 70° F-day will have 0 HDDs, while a 30° F-day will have 35 HDDs, using a base of 65° F. PSE used the three climate models described and historical temperatures to create HDDs. We used the HDDs to model future energy demand. The climate models and historical data are from the National Oceanic and Atmospheric Administration's (NOAA's) Sea-Tac Airport station.

Previously, we calculated HDDs by using the most recent 30 years of recorded temperatures and used that static calculation through the forecast period, creating a flat normal temperature. For this IRP, PSE calculated the HDDs for each forecast year using a different set of temperatures. We calculated HDDs for each forecast year using temperatures from the prior 15 years and temperatures from the future 15 years, including the year of interest. If the preceding 15 years included years from which historical temperatures were available, then we used the historical data. We used temperatures from the three climate models for future years. Figure 5.1 shows an example of the old and the new normal temperatures, which include climate change.

Figure 5.1: Heating Degree Days, Previous Normal Temperature, and Current Normal Temperature Assumptions (HDD base temperature 65º F)




➔ See Appendix D: Demand Forecasting Models, for more information about calculating the HDDs that went into the demand forecast.

## 2.4. Design Temperature for Peak Demand Forecast

We do not plan the gas peak demand to a normal or average temperature but for a design peak temperature. Puget Sound Energy defines the design peak temperature as one with a 1-in-50 chance of occurrence per year. When we incorporated climate change into the design peak temperature, we used the same considerations we described for the energy forecast. This allowed us to:

1. Incorporate future temperatures into the design temperature forecast.
2. Ensure the temperature is in the proper framework for planning.
3. Ensure the new calculation is objective.

We used all three models and historical data to calculate the design day. However, to calculate a design day, we had to balance having enough data to calculate a 1-in-50 chance of occurrence while not using too much historical data that could be outdated. To get enough years of data to evaluate a 1-in-50 peak occurrence, we used historical data from 2010 to 2019 and data from the three climate change models for 2020 to 2049. Therefore, we used 98 observations to calculate the peak temperature with a 1-in-50 chance of occurring. Based on this analysis, the 1-in-50 winter design peak temperature was 13⁰ F. This forecast is the same as the previous design temperature, which used 79 observations to calculate the design day temperature. We held this design temperature constant for the forecast period because rolling the calculation forward could create an unstable design peak standard.

Table 5.3: Design Temperature, Previous Design Temperature, and Current Design Temperature

| Design Day Temperature | Years in Calculation | Number of Observations | 1-in-50 Daily Temperature (ºF) |
|---|---|---|---|
| Old Design | 1950–2019 | 79 | 13 |
| New Design Incorporating Climate Change | 2010–2049 | 98 | 13 |

➔ See Appendix D: Demand Forecasting Models, for a detailed discussion of the climate change temperature calculations.

# 3. Gas Demand Forecast

In the following section, we describe the highlights of the base and zero-customer growth demand forecasts developed for PSE's gas sales service.

➔ We summarize the population and employment assumptions for the base forecasts in the Details of the Natural Gas Forecast section and explain them in detail in Appendix D: Demand Forecasting Models.

We included only demand-side resources acquired under the current 2022–2023 biennium conservation programs. In 2024 and beyond, the gas portfolio analysis helps determine the most cost-effective level of DSR to include in the gas sales portfolio.

## 3.1. Gas Energy Demand

The 2023 Gas Utility IRP base demand forecast is a forecast of both firm[2] and interruptible[3] demand because this is the volume of gas that PSE is responsible for securing and delivering to these customers. For delivery system

2 Firm customers have an agreed-upon capacity for the producer or pipeline to supply natural gas, establishing a high priority for the fuel requested. We cannot curtail the supply or delivery of natural gas under a firm contract except under unforeseeable circumstances.

3 Interruptible customers, also called non-firm customers, have lower-priority fuel supply arrangements. Under these contracts, we may stop or curtail the flow of natural gas if firm contract holders use the available capacity or if other interruptible customers outbid the power plant. Interruptible contracts are less expensive than firm contracts, reflecting the higher risk of disrupted fuel receipts.

planning, however, transport demand must be included in total demand; transport customers[4] purchase their gas elsewhere but contract with PSE for delivery.

In this IRP base demand forecast, we project gas energy demand before additional DSR grows at a 0.4 percent average annual growth rate (AARG) from 2024 to 2050; this would increase demand from 93,942 MDth in 2024 to 103,611 MDth in 2050 (Figure 5.2). This rate is lower than the annual growth rate of 0.8 percent we identified in the 2021 IRP base demand forecast. The growth rate is lower than the 2021 IRP base demand forecast because we incorporated warming during the heating season from climate change in this forecast. We did not include the warming effects of climate change in the 2021 IRP base demand forecast.

Before additional DSR, the 2023 IRP zero-customer growth forecast projects a -0.3 percent average annual growth rate (Table 5.4).

[4] Transport customers, in the gas industry, are customers who acquire their gas from third-party suppliers and rely on the utility for distribution. It does not refer to natural gas-fueled vehicles.

Figure 5.2: Gas Energy Demand Forecast before Additional DSR Base and Zero-customer Growth Scenarios, Without Transport Load (MDth)

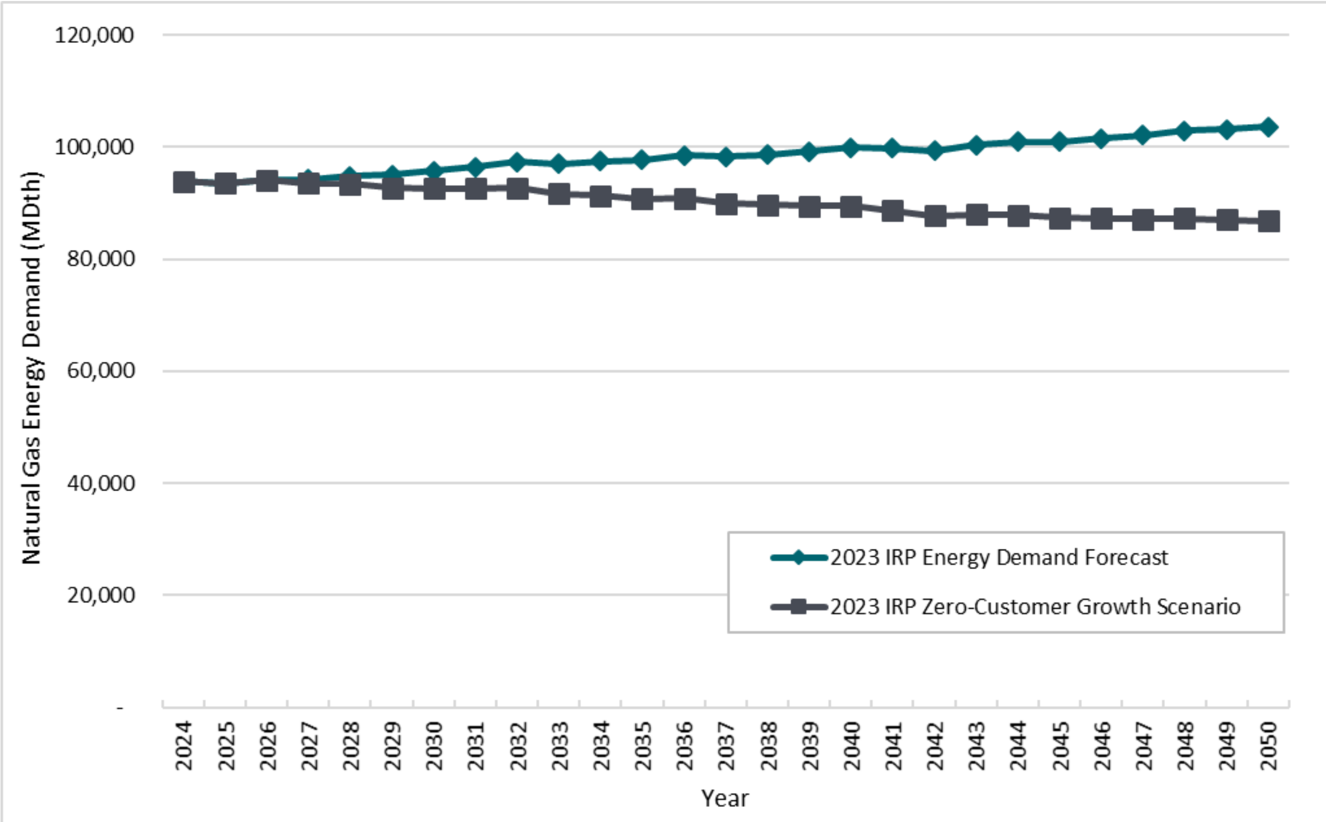



Table 5.4: Gas Energy Demand Forecast before Additional DSR Base and Zero-customer Growth Scenarios without Transport (MDth)

| Scenario | 2024 | 2030 | 2035 | 2040 | 2045 | 2050 | AARG 2024–2050 (%) |
|---|---|---|---|---|---|---|---|
| Base Demand Forecast | 93,942 | 95,728 | 97,695 | 99,919 | 101,033 | 103,611 | 0.4 |
| Zero-customer Growth Demand Forecast | 93,942 | 92,673 | 90,806 | 89,468 | 87,372 | 86,816 | -0.3 |

## 3.2. Gas Peak Demand

We modeled the gas design peak day at the day's 13° F average temperature. We included only firm sales customers when forecasting peak gas demand, not transport and interruptible customers. For peak gas demand, this IRP base demand forecast projects an average increase of 0.7 percent per year from 2024 to 2050; peak demand would rise from 995 MDth in 2024 to 1,189 MDth in 2050. The zero-customer growth demand forecast projects a 0.0 percent annual growth rate (Figure 5.3 and Table 5.5).

Figure 5.3: Gas Peak Day Demand Forecast before Additional DSR
Base and Zero-customer Growth Scenarios (13 Degrees, MDth)

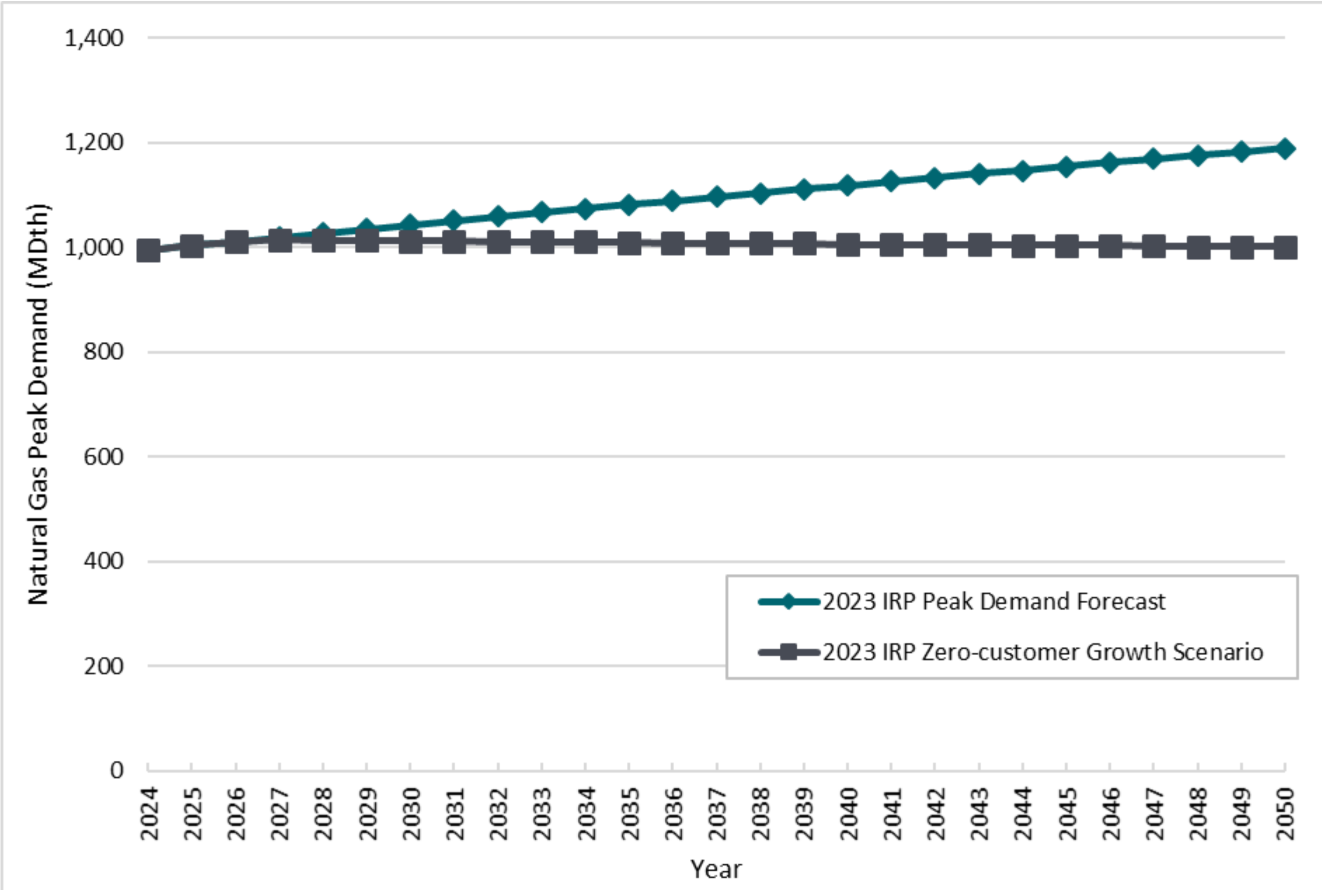
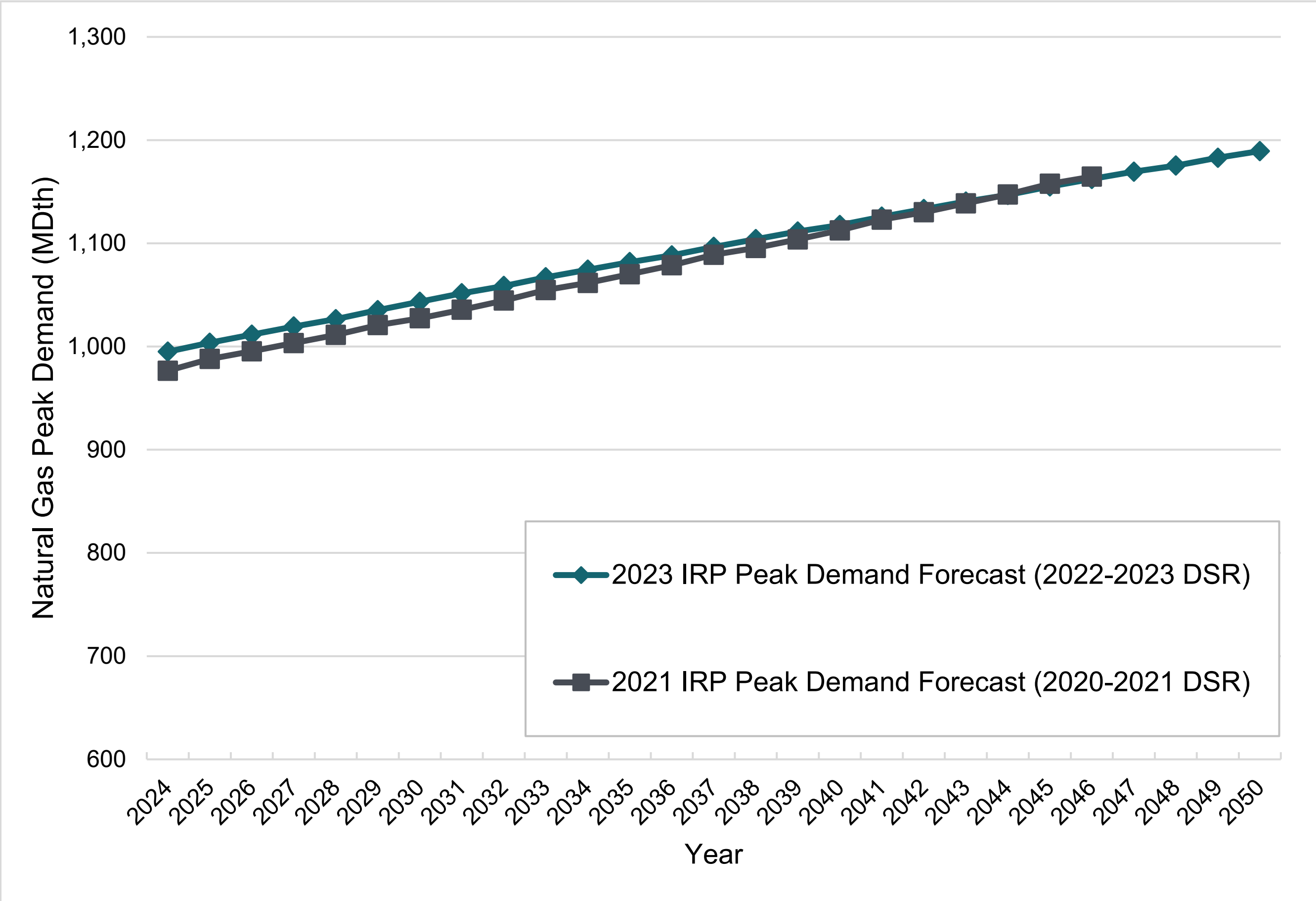



Table 5.5: Gas Peak Day Demand Forecast before Additional DSR
Base and Zero-customer Growth Scenarios (13 Degrees, MDth)

| Scenario | 2024 | 2030 | 2035 | 2040 | 2045 | 2050 | AARG 2024–2050 (%) |
|---|---|---|---|---|---|---|---|
| Base Demand Forecast | 995 | 1,043 | 1,082 | 1,118 | 1,155 | 1,189 | 0.7 |
| Zero-customer Growth Demand Forecast | 995 | 1,013 | 1,010 | 1,006 | 1,004 | 1,001 | 0.0 |

The peak demand growth rate in the 2023 base forecast is slightly lower than that in the 2021 base forecast (0.8 percent), but the peak demand starts higher than the 2021 IRP peak demand. The slight change in the peak demand forecast is because we included a snow day variable in the peak model. See the Updates to Inputs and Equations section for a description of the snow day variable. Also, climate change did not change the design peak temperature, so the peak demand did not change when we included climate change. See the Climate Change section for a description of climate change assumptions for the design peak temperature.

Figure 5.4: Firm Gas Peak Day Forecast before Additional DSR
2023 Gas Utility IRP Base Peak Demand Forecast versus 2021 IRP Base Peak Demand Forecast
Daily Annual Peak (13 Degrees, MDth)




## 3.3. Impacts of Demand-side Resources Illustrated

As explained at the beginning of this chapter, the gas demand forecasts include only demand-side resources implemented through December 2023 since the demand forecast helps determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of DSR on energy and peak forecasts, the cost-effective amount of DSR determined in this IRP is applied to the energy demand (without transport) and peak demand forecast for 2024 to 2050. We determined the preferred portfolio and the cost effective DSR for the zero-customer growth scenario, therefore we show the zero-customer growth scenario and the zero-customer growth scenario after DSR in this section.

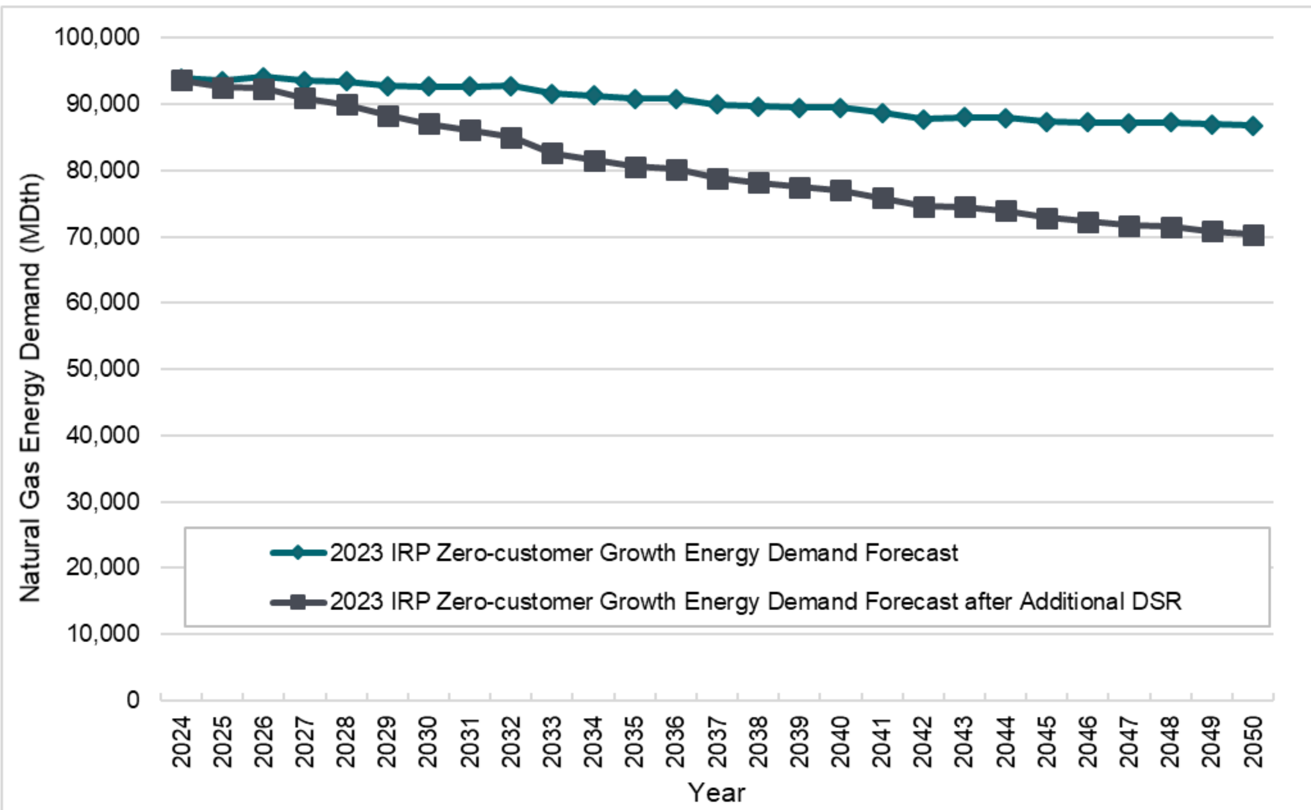
➔ For more details on the DSR analysis, see Chapter Six: Gas Analysis, and Appendix C: Conservation Potential Assessment.

To account for the 2017 general rate case,[5] we also applied an additional five percent of DSR for that period. We use forecasts with DSR internally for financial and system planning decisions. We illustrate the results in Figures 5.5 and 5.6.

When we applied the DSR bundles chosen in this IRP portfolio analysis:

- Gas zero-customer growth energy demand in 2050 is reduced by 19 percent to 70,348 MDth.
- Gas zero-customer growth energy demand will decline at an average annual rate of 1.1 percent from 2024 to 2050.

Figure 5.5: Gas Zero-customer Growth Energy Demand Forecast, before Additional DSR and after Additional DSR

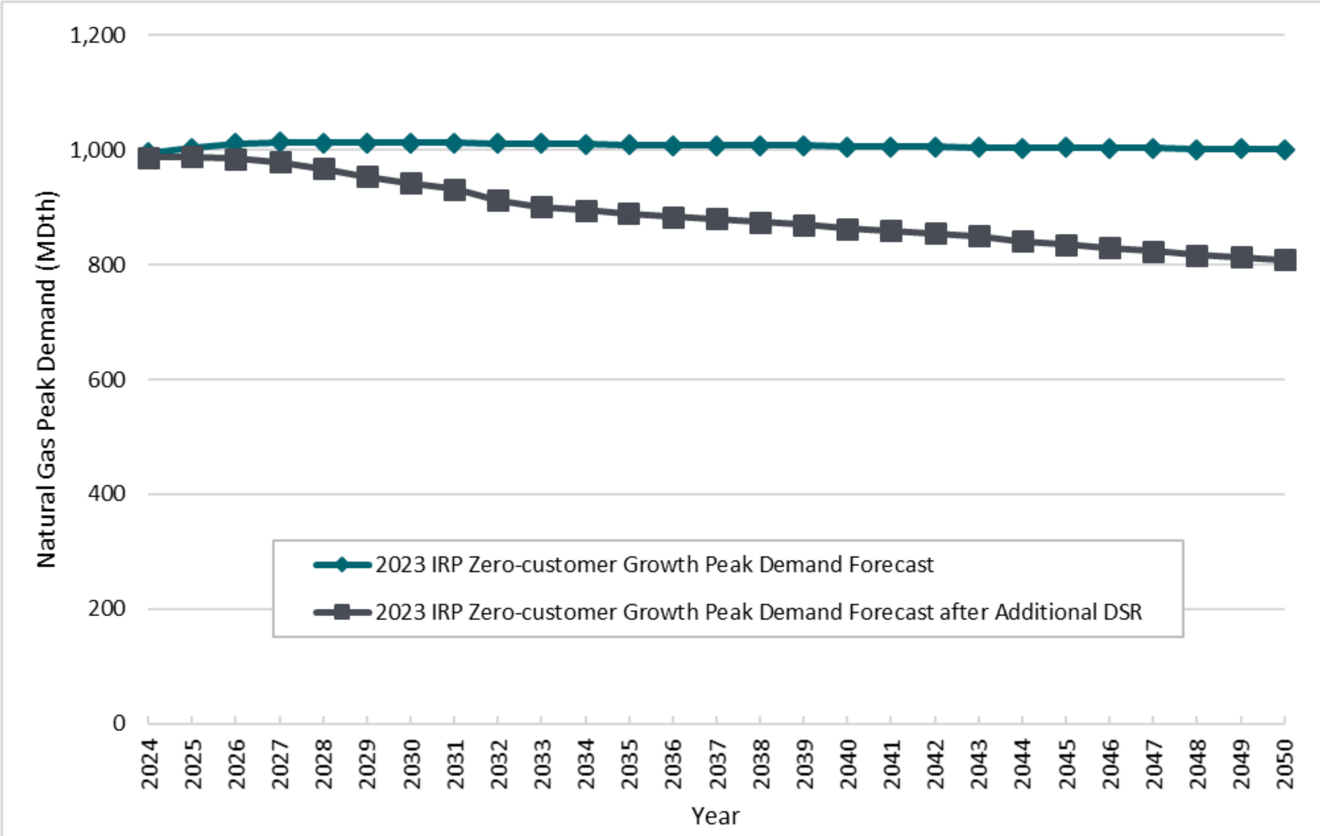



When we applied the DSR bundles chosen in this IRP portfolio analysis to the zero-customer growth demand:

- Gas system peak demand in 2050 is reduced by 19 percent to 809 MDth.
- Gas system peak demand will decrease at an average annual rate of 0.76 percent from 2024 to 2050.

[5] Final Order Rejecting Tariff Sheets; Approving and Adopting Settlement Stipulation; Resolving Contested Issues; and Authorizing and Requiring Compliance Filing, Dockets UE-170033 and UG-170034 (consolidated), Washington Utilities and Transportation Commission. Page 85 Line 250.

Figure 5.6: Natural Gas Base Peak Demand Forecast, before Additional DSR and after Additional DSR




Unlike prior IRPs, this IRP also includes electrification as part of the CCA scenarios; we determined the impact of these scenarios on the demand forecast in the gas portfolio modeling, and they are an output of that analysis.

➔ We discuss these impacts of electrification on the demand forecast in Chapter Six: Gas Analysis.

## 3.4. Details of the Gas Forecast

The gas forecast is comprised of demand from several different classes. The firm classes are residential, commercial, industrial, commercial large volume, and industrial large volume. The interruptible classes are commercial and industrial. Transport classes are commercial firm, commercial interruptible, industrial firm, and industrial interruptible. Residential customers are approximately 93 percent of PSE's gas customers and are expected to grow by 0.9 percent per year. Commercial customers are about 6.5 percent of PSE's customers and are expected to grow at 0.2 percent per year. Between now and 2050, we expect demand from these classes to grow at 0.6 percent and 0.4 percent annually.

We describe the details for each customer class in Appendix D: Demand Forecasting Models.

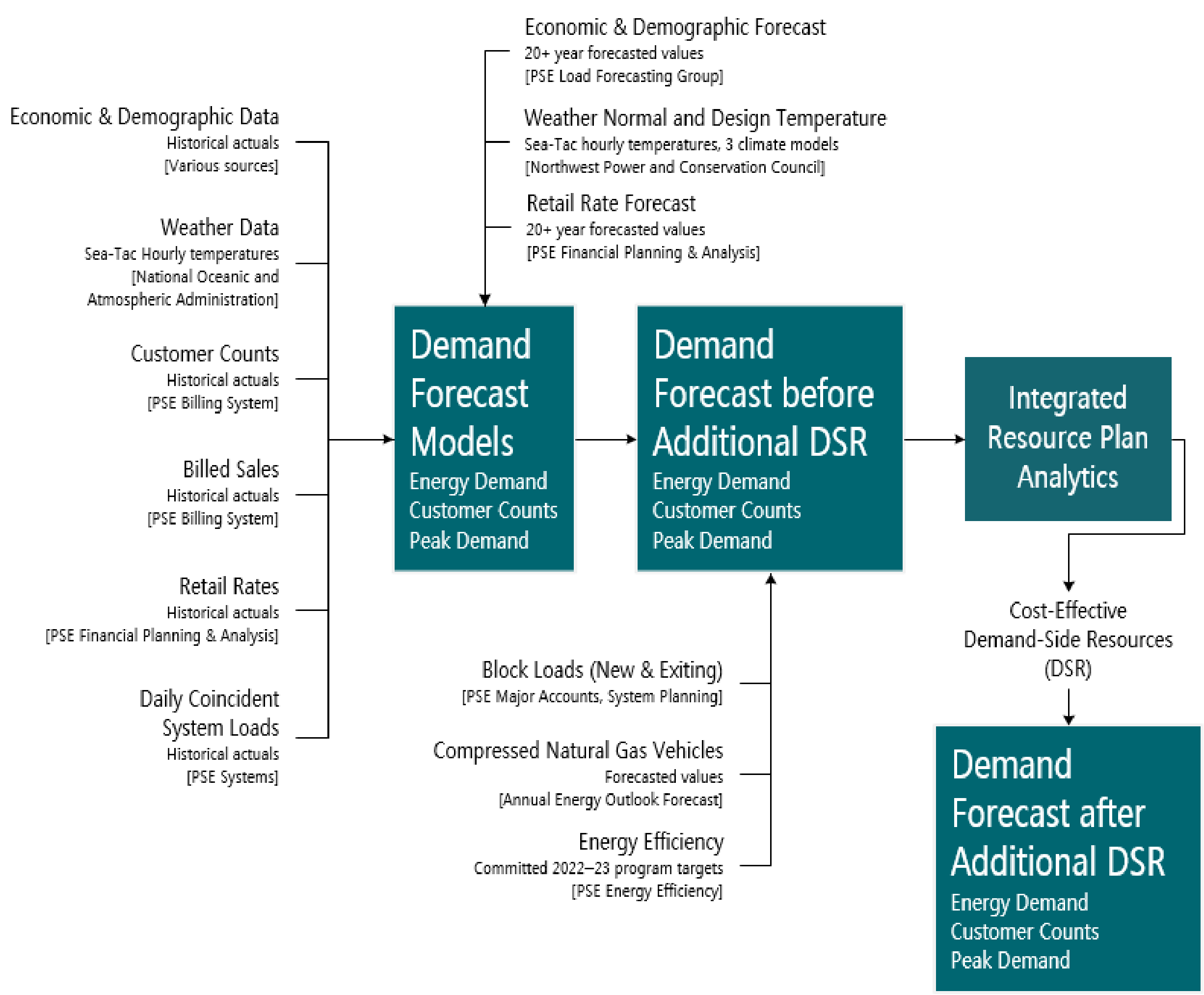
# 4. Methodology

We identify relationships between historical growth and historical conditions to forecast customer demand. Therefore, we can use forecasted future conditions to forecast future growth. The following section discusses how we forecast demand.

## 4.1. Forecasting Process

Puget Sound Energy's regional economic and demographic model uses national and regional data to forecast total employment, employment types, unemployment, personal income, households, and consumer price index (CPI) for the PSE gas service area. For this analysis, we used regional economic and demographic data from county-level information from various sources. This financial and demographic information is combined with other PSE internal information to produce energy and peak demand forecasts for the service area. We illustrate the demand forecasting process in Figure 5.7 and list the economic and demographic input data sources in Table 5.6.

Figure 5.7: Puget Sound Energy Demand Forecasting Process



We divide customers into classes that use energy for similar purposes and at comparable retail rates to forecast energy sales and customer counts. We model the different classes separately using variables specific to their usage patterns. Customer classes include firm: residential, commercial, industrial, commercial large volume and industrial large volume; interruptible: commercial and industrial; and transport: commercial firm, commercial interruptible, industrial firm, and industrial interruptible.

We used multivariate time series econometric regression equations to derive historical relationships between trends and drivers. We then forecasted the number of customers and use per customer by class or service level. We multiplied these to arrive at the billed sales forecast. The main drivers of these equations include population, retail rates, weather, total employment, manufacturing employment, and CPI. Demand, presented in this chapter, is calculated from sales, and includes losses in addition to sales. We base weather inputs on temperature readings from Sea-Tac Airport and include historical and forecasted temperatures, including the effects of climate change. We also projected peak system demand by examining the historical relationship between actual peaks, the temperature at peaks, and the economic and demographic impacts on system demand.

➔ See Appendix D: Demand Forecasting Models, for detailed descriptions of the econometric methodologies used to forecast billed energy sales, customer counts, peak loads, and forecast uncertainty.

Table 5.6: Sources for County Economic and Demographic Data in the Economic and Demographic Model

| County-level Data | Source |
|---|---|
| Labor force, employment, unemployment Rate | U.S. Bureau of Labor Statistics (BLS) |
| Total non-farm employment and breakdowns by type of employment | WA State Employment Security Department (WA ESD), using data from the Quarterly Census of Employment and Wages |
| Personal income | U.S. Bureau of Economic Analysis (BEA) |
| Wages and salaries | U.S. Bureau of Economic Analysis (BEA) |
| Population | WA State Employment Security Department (WA ESD) |
| Households and household size, single- and multi-family | U.S. Census |
| Aerospace employment, Regional Consumer Price Index (CPI) | Puget Sound Economic Forecaster |

We obtain U.S. economic and demographic data from Moody's Analytics. We applied the following Moody's inputs to PSE's economic and demographic model: GDP, industrial production index, employment, unemployment rate, personal income, wages and salary disbursements, CPI, housing starts, population, conventional mortgage rate, and three-month T-bill rate.

## 4.2. Zero-customer Growth Scenario

We developed a zero-customer growth scenario to analyze how the gas portfolio would be affected when no new gas customers were added to the system. In this scenario, we added zero-customers to the system after 2026. This analysis only affects residential and commercial classes as industrial customers are declining. The underlying economic and demographic forecasts are the same as the base forecast and the zero-customer growth scenario assumes zero growth in new customers is due to policy decisions.

➔ Analysis with the zero-customer growth scenario is available in Chapter Six: Gas Analysis.

## 4.3. Stochastics

We developed stochastic simulations with stochastic outputs from our economic and demographic model and future temperatures from three climate models. The stochastic simulations reflect variations in key regional economic and demographic variables such as population, employment, and income. The simulations also vary the equations to include potential modeling variances. Stochastic scenarios also use future temperatures from the CanESM2_BCSD, CCSM4_BCSD, and CNRM-CM5_MACA models, reflecting higher or lower temperature conditions. We sampled forecasted temperature years 2020 to 2049 from the three climate models. We used temperature changes and economic and demographic data to create 250 stochastic draws.

We then ran the 250 gas stochastic scenarios in SENDOUT, a gas supply planning and asset valuation tool.

➔ Detailed descriptions of the stochastic scenarios are available in Chapter Six: Gas Analysis. See Appendix D: Demand Forecasting Models, for a detailed discussion of the stochastic simulations.

## 4.4. Updates to Inputs and Equations

The following section summarizes updates to the demand forecast inputs and equations made since the 2021 IRP.

### 4.4.1. Climate Change Forecast

Previous IRPs used the most recent 30 years of historical temperatures to predict temperatures for the forecast period. In this IRP, we used the three climate change models the Northwest Power and Conservation Council (NWPCC) used to forecast future temperatures.

➔ See the Climate Change section of this document for more details on how we used climate models in the forecast.

### 4.4.2. Peak Model Updates

We used a new variable in the peak model for this IRP to improve the forecasted peak usage. In this IRP, PSE incorporated a snow day variable in the peak model as part of the standard process improvement of our models. This binary variable was 1 if it was snowing during the day or if there was snow on the ground. The variable was 0 if there was no snow. This variable was significant in the peak model and helped account for the fact that usage can be different on a snow day compared to a cold day with no snow.

### 4.4.3. Code Updates

The 2018 Washington State energy code change and the Seattle policy to limit natural gas use were effective in 2021 and 2022, respectively. The effects of these two code changes through 2023 were considered in this forecast before additional DSR to understand better the forecast's starting point in 2024. The conservation potential assessment (CPA) determined the effects of these code changes starting in 2024 and included the statutory requirement for the Washington State code cycle to make the code more stringent in terms of energy use. The law requires that the Washington State code be improved in each code cycle update to achieve a 70 percent reduction in energy use by 2031 compared to the 2006 code baseline. Therefore, a small amount of these code changes is in the demand forecast before additional DSR, but most of this code change will be accounted for in the after additional DSR forecast.

# 5. Key Assumptions

To develop PSE’s demand forecasts, we made assumptions about economic growth, energy prices, weather, and loss factors, including certain system-specific conditions. We describe these and other assumptions in the next section.

## 5.1. Economic Growth

Economic activity has a significant effect on long-term energy demand. Although the energy component of the national gross domestic product (GDP) has been declining over time, gas is still a significant input into various residential end uses such as space heating, water heating, cooking, and clothes drying. Therefore, growth in the residential building stock directly impacts the demand for gas over time. Commercial and industrial sectors also use gas for space heat and water heating. Gas is also an essential input in many industrial production processes. Economic activities in the commercial and industrial sectors are crucial indicators of the overall trends in gas consumption.

## 5.2. National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with solid links to the national economy, this IRP demand forecast begins with assumptions about what is happening in the broader U.S. economy. Puget Sound Energy relies on Moody’s Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy for economic growth rates. We used the November 2021 Moody’s forecast for this IRP. The Moody’s forecast predicts:

- The economy will be tethered to the COVID-19 pandemic in 2021.

- The economy will continue to recover with a return to full employment in 2023, and labor force participation will continue to increase as workers get healthy and children are vaccinated.
- The recovery will continue through 2025. After 2025, Moody's predicts the economy will grow modestly over the long term.
- United States Gross Domestic Product (GDP) will continue to grow over the forecast period with a 2.0 percent average annual growth from 2024 to 2050. This growth rate is lower compared to Moody's forecast used in the 2021 IRP, which projected a 2.2 percent average yearly growth. Some of the 2021 IRP growth was from the projected recovery from COVID-19.

Moody's identified possible risks that could affect the accuracy of this forecast:[6]

- COVID-19 is still unpredictable in its effects on the economy; more waves that elude the vaccine could halt the recovery.
- In the near term, supply constraints could cause the economy to grow less quickly.
- Rising long-term interest rates could cause a slump in the economic recovery.
- The congressional stimulus for COVID-19 could be smaller than predicted or not provide the expected economic boost.

## 5.3. Population Outlook

The Washington State Employment Security Department (WA ESD) average annual growth rate for the counties that make up the gas service area is 0.97 percent from 2024 to 2050. This growth rate is down slightly from the 1.0 percent growth rate forecast in the 2021 IRP for 2022 to 2045.

## 5.4. Regional Economic Outlook

Puget Sound Energy prepares regional economic and demographic forecasts using econometric models based on historical financial data for the counties in PSE's service area and the macroeconomic forecasts for the United States.

Our gas service area stretches from south Puget Sound to upper Snohomish County and from central Washington's Kittitas Valley west to Seattle and Olympia. We serve more than 860,000 gas customers in six counties.

Within PSE's service area, demand growth is uneven. Growth in the high-tech, information technology, or retail (including online retail) sectors drives most of the economic progress. Supporting industries like leisure and hospitality employment are also growing. Job growth is concentrated in King County, which accounts for more than half of the system's gas sales demand today. Other counties are growing, but typically more slowly, and have added fewer jobs.

## 5.5. Gas Service Area Outlook

We used the following forecast assumptions in this IRP base demand forecast.

[6] Moody's Analytics (2021, November) Forecast Risks. Precis U.S. Macro. Volume 26 Number 8.

- An inflow of 1.32 million new residents (by birth or migration) will increase the local area population to 5.98 million by 2050, for an average annual growth rate of 0.97 percent. This growth rate is slightly lower than the 2021 IRP forecast, which projected an average annual population growth of 1.0 percent that would have resulted in 5.45 million gas service area residents by 2041.
- Employment will grow at an average annual rate of 0.6 percent between 2024 and 2050, which is slower than the annual growth rate forecasted in the 2021 IRP of 1.2 percent. The employment growth rate in the 2021 IRP included the recovery from the COVID-19 recession, leading to a higher growth rate.
- Local employers will create about 406,000 total jobs between 2024 and 2050, compared to about 555,000 jobs forecasted in the 2021 IRP between 2022 and 2041.
- Manufacturing employment will decline by 0.2 percent annually on average between 2024 and 2050 due to outsourcing manufacturing processes to lower wage or less expensive states or countries and the continuing trend of capital investments that create productivity increases.
- Population and employment growth rates are less closely aligned as the economy grows quickly from the COVID-19 recovery and the area experiences retirements from the baby boomer generation.

We show the population and employment forecasts for PSE's gas service area in Table 5.7.

Table 5.7: Population and Employment Growth, Gas Service Counties (1,000s)

| Model Driver | 2024 | 2030 | 2035 | 2040 | 2045 | 2050 | AARG 2024–2050 (%) |
|---|---|---|---|---|---|---|---|
| Population | 4,656 | 4,958 | 5,201 | 5,416 | 5,642 | 5,979 | 0.97 |
| Employment | 2,348 | 2,470 | 2,562 | 2,635 | 2,704 | 2,755 | 0.6 |

## 5.6. Weather

In this IRP, we incorporated climate change temperatures from three climate models to calculate the normal temperatures for the base energy demand forecast. The design peak temperature for the base peak demand forecast also includes climate change.

➔ The Climate Change section of this chapter and Appendix D: Demand Forecasting Models discuss how we created this forecast.

## 5.7. COVID-19 Impacts

We incorporated COVID-19 adjustments to the forecast in 2022 but made no additional adjustments in 2023 and later, above and beyond the effects of the economic forecast that was incorporated into the demand forecast using the macroeconomic variables. The result was an economic recovery through 2025, with lingering effects from the recession persisting throughout the remainder of the forecast. There is a great deal of uncertainty around the steady state level of residential and commercial usage once behaviors developed during the pandemic settle.

PSE performed stochastic simulations that varied the economic forecast around this base, including simulations with better and worse economic outcomes. Since the IRP determines the resource need starting in 2024, the stochastic simulations show alternative ways the pandemic could resolve in the future.

# 5.8. Gas Decarbonization

This IRP considers the effects of gas decarbonization, which includes the impact of Seattle's and Shoreline's policies that limit natural gas use in commercial and large multi-family buildings. This IRP also considers the current Washington State energy code change that encourages residential builders to install electric space heating and water heating equipment instead of gas.

The base demand forecast considers the effects of the Seattle policy and the 2018 Washington State energy code change from 2022 to 2023. For years 2024 and beyond, the CPA will estimate the effects of local policies, the current Washington State energy change, and future Washington State energy code changes. Other decarbonization effects on the gas system, such as the Climate Commitment Act, were considered through the SENDOUT modeling process but are not included in the base demand forecast before additional DSR.

# 5.9. Loss Factors

The gas loss factor in this IRP is 0.93 percent. The loss factors assumed in the demand forecast are system-wide average losses during normal operations for the past two to three years and are updated annually.

# 5.10. Block Load Additions

Beyond typical economic change, the demand forecast also considers known major demand additions and deletions that we would not account for through normal demand growth. These are major infrastructure projects or changes to usage by a large customer. These additions or deletions to the forecast are called block loads, and they use the information provided by PSE's system planners or major account representatives. The gas forecast includes a block load in the transport class, which does not affect the firm and interruptible class demand modeled in this IRP.

# 5.11. Transport Customers

We call customers who purchase their gas from other suppliers, transport customers; they rely on PSE for distribution services. We removed transport customers from the forecast before determining the supply-side resource need because PSE is not responsible for acquiring supply resources for transport customers. However, we analyzed smaller transport customers in this IRP to assess their energy efficiency potential.

# 5.12. Interruptible Loads

For several gas utility customers, all or part of their demand is interruptible demand. We assumed interruptible gas demand would be curtailed when forecasting peak gas demand.

## 5.13. Compressed Gas Vehicles

We added compressed natural gas (CNG) vehicles to this IRP base demand forecast. The CNG vehicle forecast included buses, rail, light-duty, medium-duty, and heavy-duty vehicles. In 2024, this adds 229 MDth to the forecast. We expect this demand to grow at an average annual rate of 5.4 percent, based on the Annual Energy Outlook 2021 published by the U.S. Department of Energy.

## 5.14. Retail Rates

We included retail energy prices — what customers pay for energy — as explanatory variables in the demand forecast models because they affect customer choices in the long run. These choices impact the efficiency level of newly acquired appliances, how customers use those appliances, and the type of energy source they use to power them. The energy price forecasts draw on information obtained from internal and external sources.

# 6. Previous Demand Forecasts

The following section compares actual peak demand to previous IRP forecasts. This section also identifies reasons prior forecasts may be off from current weather-normalized actual peaks.

## 6.1. Peak Demand Forecasts Compared to Actual Peaks

Weather-normalized actual gas peak demand is compared to the gas peak forecasts after additional DSR from 2011, 2013, 2015, 2017, 2019,[7] and 2021 IRPs in Figure 5.8 and Table 5.13. We show the difference in the normalized actual values compared to the previous IRPs in Table 5.8.

[7] A formal IRP report was not filed by PSE in 2019. On October 28, 2019, the Washington Utilities and Transportation Commission Staff filed a Petition for Exemption from WAC 480-100-238 pursuant to WAC 480-07-100 until December 31, 2020. On November 7, 2019 the Commission held an Open Meeting concerning this matter and subsequently issued Order 2, exempting PSE (and other investor-owned utilities in Washington) from WAC 480-100-238. Pursuant to Order 2, PSE filed an IRP Progress Report in 2019.

Figure 5.8: Observed Weather Normalized Gas Peak Demand Compared to Previous IRP Forecasts

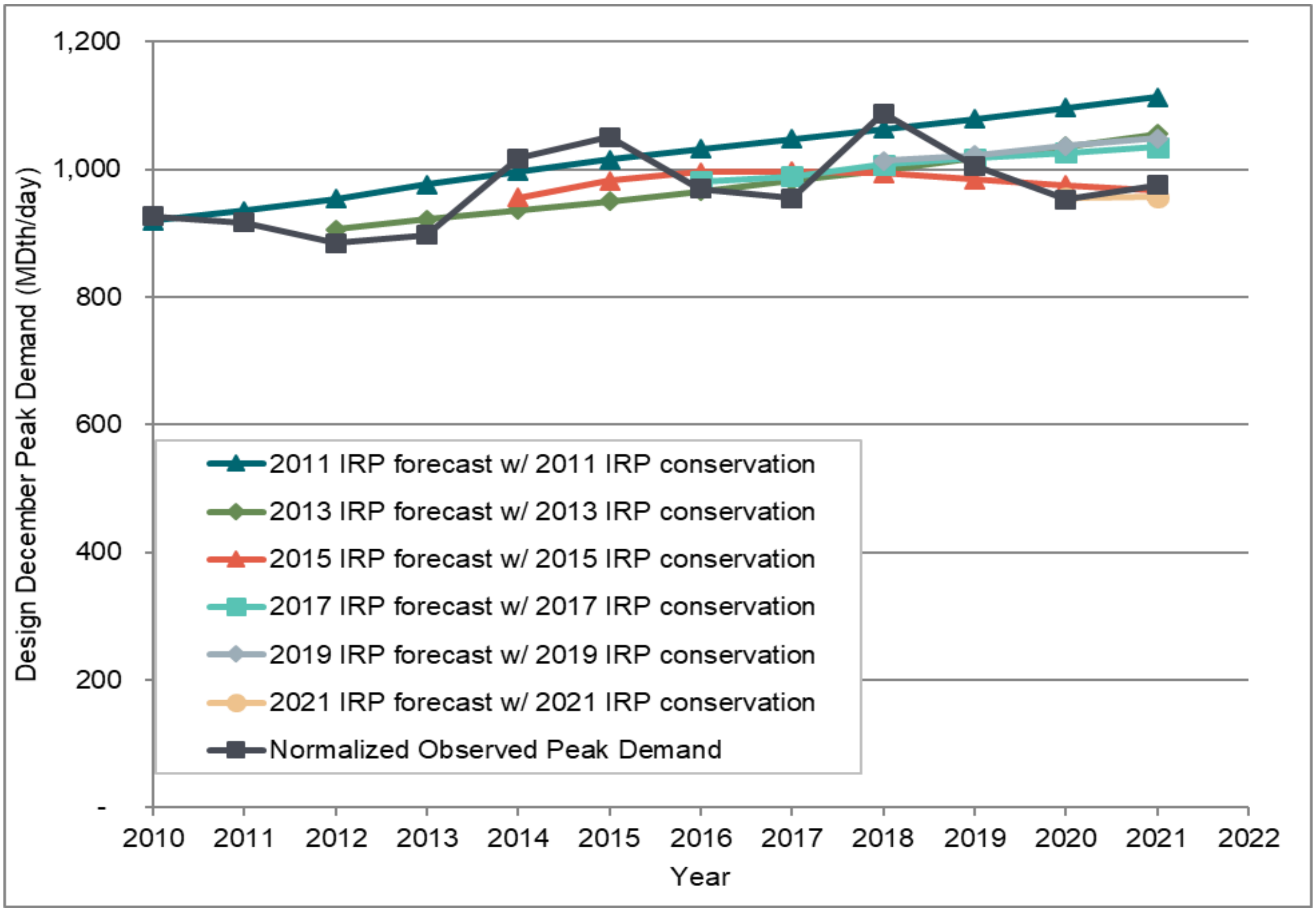



Table 5.8: Weather Normalized December Gas Peak Demand and Percent Difference from Previous IRP Forecasts

| Year | 2011 (%) | 2013 (%) | 2015 (%) | 2017 (%) | 2019 (%) | 2021 (%) |
|---|---|---|---|---|---|---|
| 2010 | -0.7 | - | - | - | - | - |
| 2011 | 2.0 | - | - | - | - | - |
| 2012 | 7.8 | 2.4 | - | - | - | - |
| 2013 | 8.8 | 2.7 | - | - | - | - |
| 2014 | -2.0 | -7.9 | -5.6 | - | - | - |
| 2015 | -3.4 | -9.6 | -6.1 | - | - | - |
| 2016 | 6.4 | -0.4 | 3.2 | 1.2 | - | - |
| 2017 | 9.7 | 2.8 | 5.0 | 3.6 | - | - |
| 2018 | -2.3 | -8.2 | -8.2 | -7.4 | -6.9 | - |
| 2019 | 7.3 | 1.1 | -1.7 | 1.1 | 1.6 | - |
| 2020 | 15.0 | 8.7 | 2.8 | 7.6 | 8.8 | 0.2 |
| 2021 | 14.1 | 8.2 | -0.3 | 6.1 | 7.5 | -1.8 |

# 6.2. Reasons for Forecast Variance

As explained throughout this chapter, we based this IRP peak demand forecasts on forecasts of key demand drivers, including expected economic and demographic behavior, DSR, customer usage, and weather. When forecasts of these drivers diverge from observed actual behavior, so does this IRP forecast. As forecasts age, assumptions and conditions may change, so we expect older forecasts to be farther off from observed actuals than more recent forecasts. We explain these differences in the next section.

## 6.2.1. Economic and Demographic Forecasts

Economic and demographic factors are key drivers for this IRP peak demand forecast. After the 2008 recession hit the U.S., many economists, including Moody's Analytics, assumed the economy would recover sooner than it did. Experts pushed out a complete recovery with each successive forecast as the U.S. economy failed to return to its previous state. The charts below compare Moody's estimates of U.S. housing starts and population growth incorporated in the 2011 IRP through the 2019 IRP with actual U.S. housing starts and population growth.

Moody's optimistic forecasts of housing starts and population growth during the recession led to over-estimated forecasts of customer counts. Since the 2019 IRP, we no longer used estimates of housing starts as a driver in the demand forecast. Instead, we now use population projections based on WA ESD data to forecast the population in PSE's service area. For comparison, we include Moody's forecast of housing starts and population from May 2020 and Nov 2021 in Figures 5.9 and 5.10.

Although the Moody's forecast we used in the 2019 IRP predicted a softening of the economy in 2020, it did not forecast the magnitude of the effects of the COVID-19 pandemic. Therefore, the Moody's forecasts we used before the 2021 IRP likely overestimated economic growth in 2020, 2021, and 2022. We will probably not know the full extent of the pandemic's repercussions on the economy and energy demand during this IRP cycle.

Figure 5.9: Moody's Forecasts of U.S. Housing Starts Compared to Actual U.S. Housing Starts

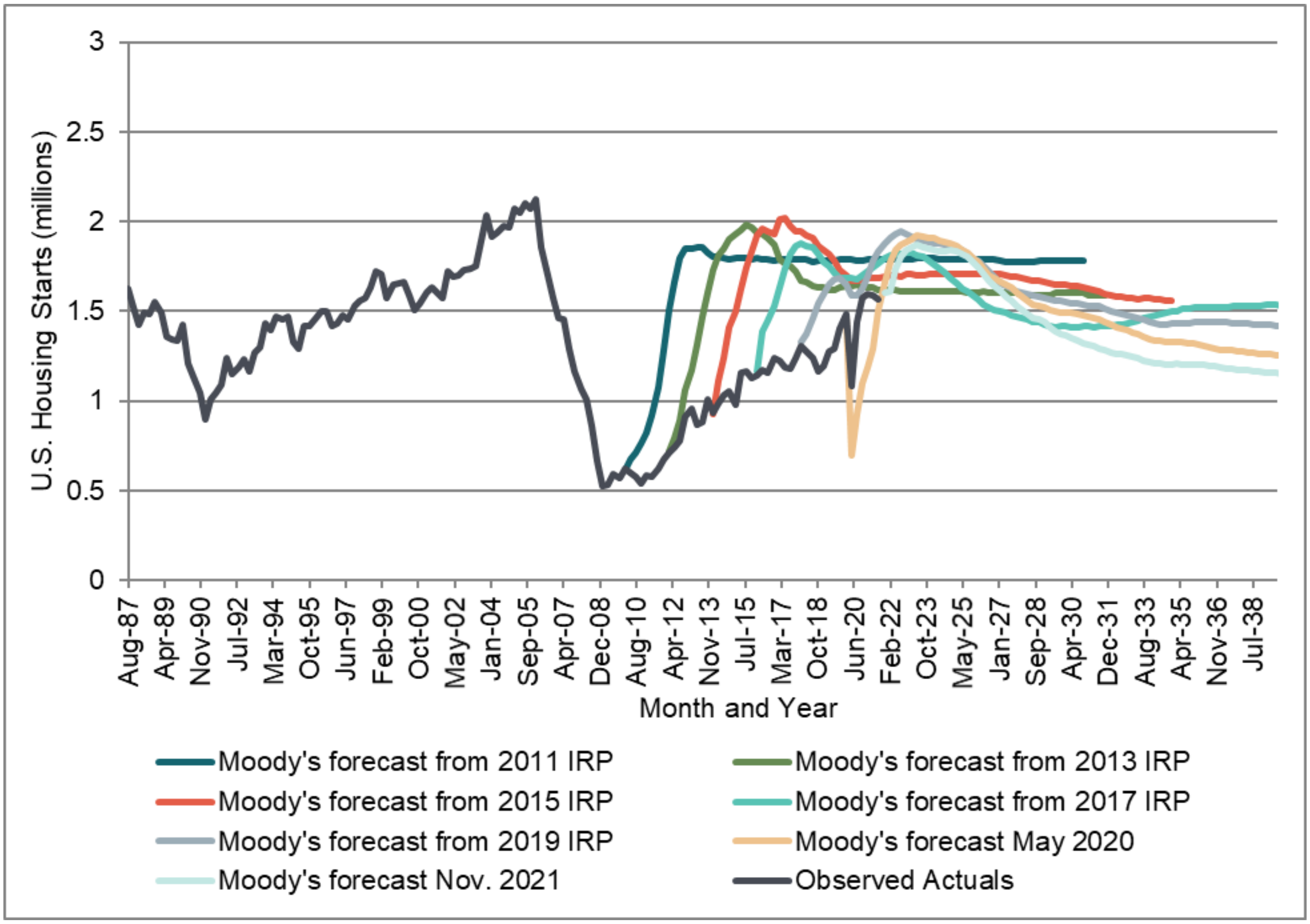
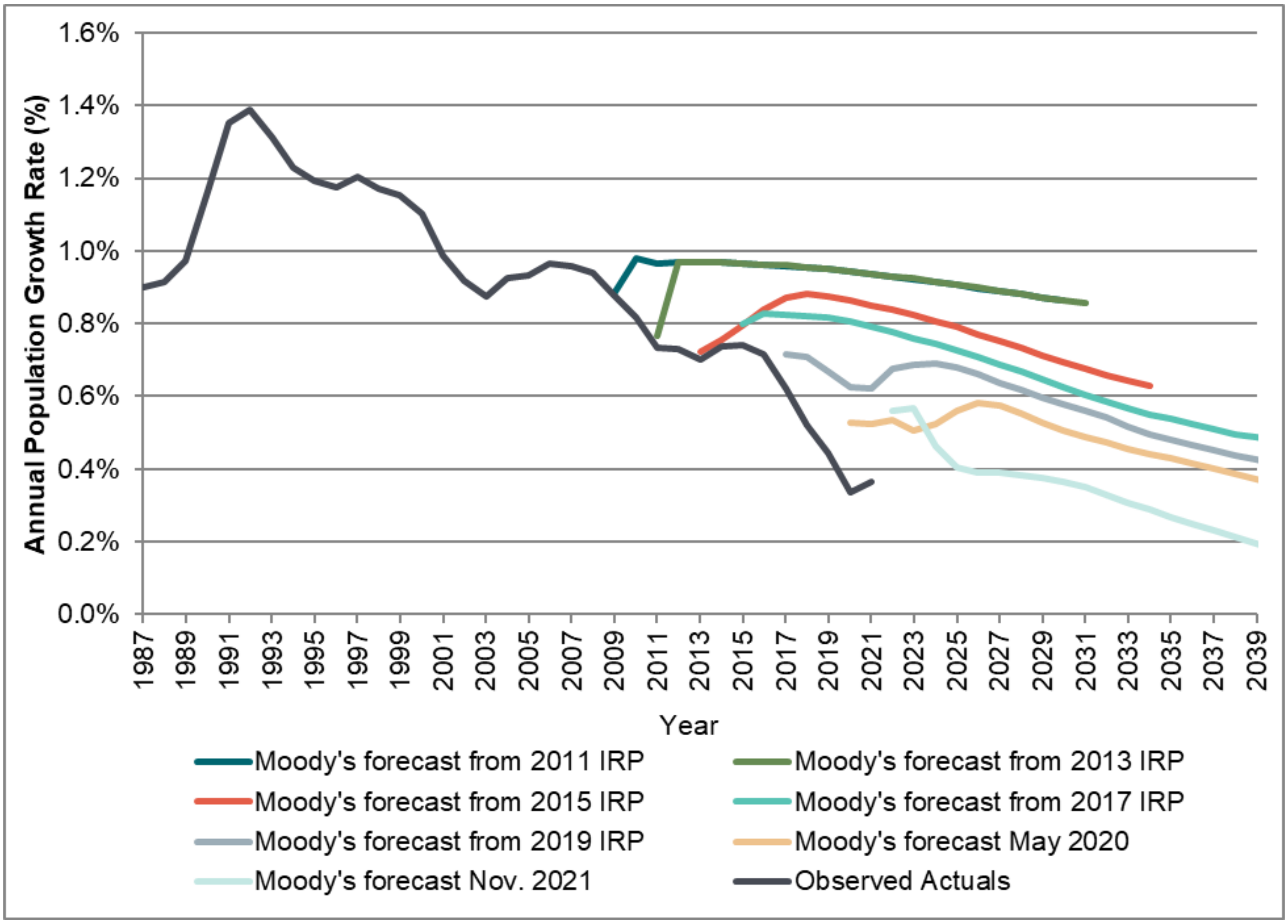


Figure 5.10: Moody's Forecasts of U.S. Population Growth Compared to Actual U.S. Population Growth




## 6.2.2. Demand-side Resources and Customer Usage

For the comparison in Figure 5.8 of weather-normalized peak observations to this IRP peak demand forecasts after additional DSR, we assumed that the forecasted DSR was implemented. However, consumers can adopt energy-efficient technologies above and beyond what utility-sponsored DSR programs and building codes and standards incentivize. This consumer behavior leads to more actual DSR taking place than forecasted. Additionally, DSR programs can change over time. We can choose programs that were not cost-effective in the past and not included in the optimal bundle in a later IRP as cost-effective. This approach can make an older forecast dated, making the forecast of DSR too low and, therefore, the demand forecast after additional DSR too high.

Also, due to the 2017 General Rate Case (GRC), PSE accelerates gas DSR by five percent each year. This accelerated DSR is an additional DSR that we did not consider in IRPs before 2017.

## 6.2.3. Normal Weather Changes

Normal weather assumptions change from forecast to forecast. From 2011 to the 2021 IRP, we updated the normal weather assumption by rolling off two older years and incorporating two new years of weather data into the 30-year average. Normal heating degree days have been declining, and the forecast of energy demand with normal weather has changed. In this IRP, we incorporated climate change into the normal definition, significantly changing the 2023 Gas Utility IRP base demand forecast.

Over time our customers' weather sensitivity has been changing. As consumers implement energy efficiency measures, customers use less energy at a given temperature, including peak temperatures. More recent forecasts reflect this change in weather sensitivity better than older forecasts.

### 6.2.4. Non-design Conditions during Observed Peaks

We model normalized peak values using the peak forecasting model. This model uses peak values from each month to create a relationship between peak demand, monthly demand, and peak temperature. However, some of the observed December peaks shown occurred on atypical days rather than typical days. For example, peaks in 2013 and 2017 fell on weekends. Peaks in 2010, 2012, and 2015 fell on New Year's Day, and the 2019 peak fell on Boxing Day (the day after Christmas). Usage on these days will likely differ from use on a typical non-holiday weekday peak. When these dates are weather normalized, they may not line up with the forecasted values since the usage patterns are atypical.

### 6.2.5. Service Area Changes

Effective January 2022, the city of Seattle banned gas in multi-family residential new construction over three stories and in commercial new construction. New construction in Seattle drove new customer growth in the residential and commercial classes, increasing the peak. Therefore, when comparing the forecasts for 2011, 2013, 2015, 2017, 2019, and 2021 IRPs to today's actuals, those forecasts are expected to be higher than the actual peak demand.