2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company

PPL companies

Case No. 2024-00326

Volume II

This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

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Executive Summary

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Electric Sales & Demand Forecast Process

PPL companies

Sales Analysis & Forecasting
October 2024

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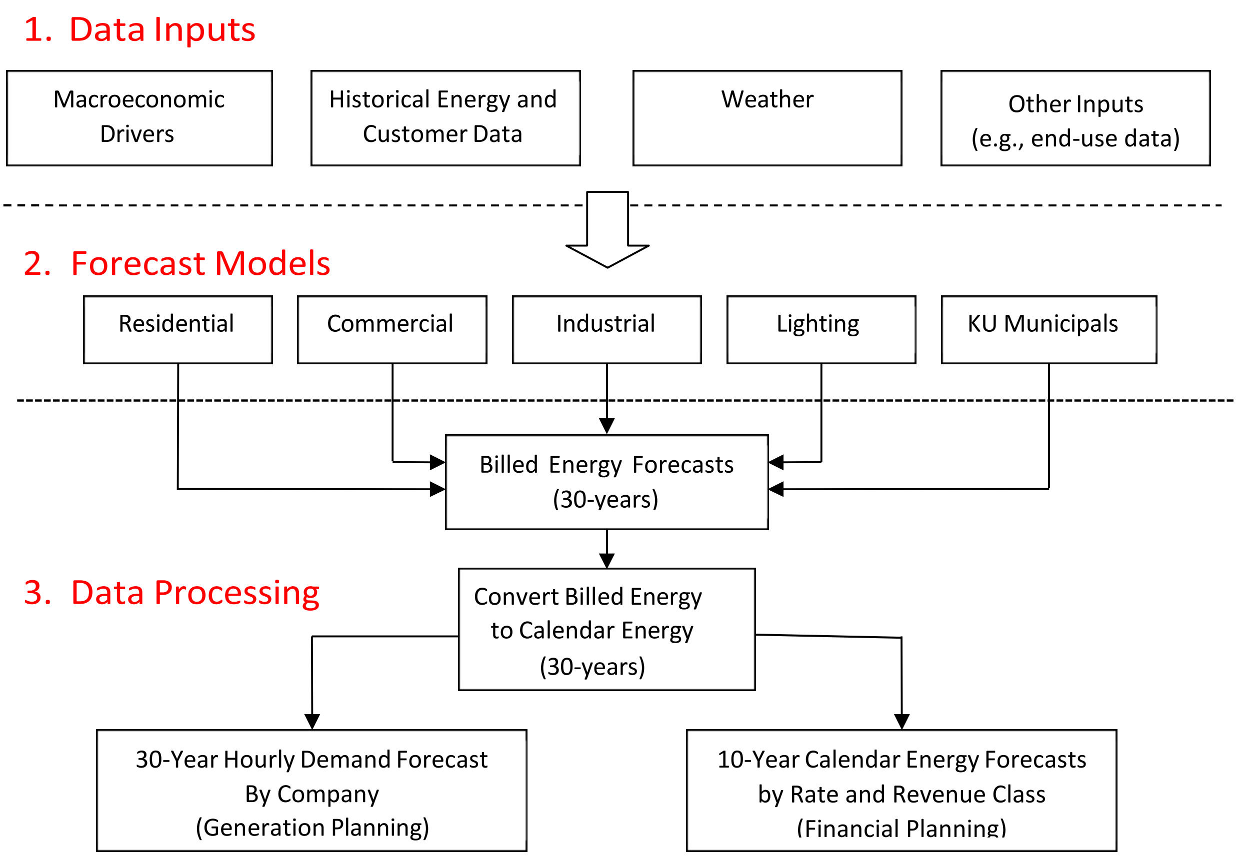
1 Introduction

The Sales Analysis & Forecasting group develops the sales and demand forecasts for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). This document summarizes the processes used to produce the sales and demand forecasts.

The forecast process can be divided into three parts (see Figure 1). The first part of the forecast process involves gathering and processing input data. Key inputs to the forecast process include macroeconomic, historical energy, customer, weather, and end-use appliance shares and efficiencies data.

Figure 1: Load Forecasting Process Diagram



In the second part of the forecast process, input data is used to specify several forecast models for each company.[1] Generally, each model is used to forecast energy sales for a group of customers with homogeneous energy-use patterns within the same or similar tariff rates. Most of the forecast models produce monthly energy forecasts on a billed basis.[2] In the third part of the forecast process, the billed

[1] Model specification is the process of determining what variables are appropriate to include or exclude from a statistical model.

[2] Customers are assigned to one of 20 billing portions. This is discussed further in Section 7.

energy forecasts are allocated to calendar months and then to rate and revenue classes for the Financial Planning department.[3] In addition, a forecast of hourly energy requirements is developed for the Generation Planning department.[4]

At many points during the forecast process, the results are reviewed to ensure they are reasonable. For example, the new forecast is compared to (i) the previous forecast and (ii) weather-normalized actual sales for the comparable period in prior years. Each part of the forecast process and the software tools used to produce the forecast are discussed in more detail in the following sections.

[3] Rate class defines the tariff assigned to each customer meter while Revenue class is a higher-level grouping; a Revenue class consists of one or more rate classes.

[4] Energy requirements are equal to sales plus transmission and distribution losses.

2 Software Tools

The following software packages are used in the forecast process:

1. Microsoft Office
2. R
3. SAS
4. Metrix ND (Itron)

SAS, R, and Metrix ND are used to specify forecast models. Microsoft Office is primarily used for analysis and presentations.

3 Input Data

Table 1 provides a summary of data inputs. The sections that follow describe key processes used to prepare the data for use in the forecast process.

Table 1: Summary of Forecast Data Inputs

Data	**Source**	**Format**
State Macroeconomic and Demographic Drivers (e.g., Employment, Wages, Households, Population)	S&P Global[5]	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	S&P Global	Annual or Quarterly – History and Forecast
Personal Income	S&P Global	Annual by County
Weather	National Oceanic and Atmospheric Administration (“NOAA”)	Daily HDD/CDD Data and Hourly Solar Irradiance by Weather Station – History
Billing Portion Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	Energy Information Administration (“EIA”), Itron	Annual – History and Forecast
Structural Variables (e.g., dwelling size, age, and type)	EIA, Itron	Annual – History and Forecast
Elasticities of Demand	EIA and Historical Data	Annual – History
Billed Sales History	CCS Billing System	Monthly by Service Territory and Rate Group
Number of Customers History	CCS Billing System	Monthly by Service Territory and Rate Group
Energy Requirements History	Energy Management System (“EMS”)	Hourly Energy Requirements by Company
Annual Loss Factors	2012 Loss Factor Study (by Management Applications Consulting, Inc.) and Historical Data	Annual Average Loss Factors by Company
Solar Installations	CCS Billing System, National Renewable Energy Laboratory (“NREL”), S&P Global	Monthly Net Metering and Qualifying Facility Customers, Private Solar Costs

[5] Formerly known as IHS Markit.

Electric Vehicles	S&P Global, Bloomberg New Energy Finance ("BNEF"), NREL, Electric Power Research Institute ("EPRI"), EIA, Kelley Blue Book	Monthly Cars on Road (historical), Monthly Cars on Road (forecast), Hourly EV Charging Shapes

3.1 **Processing of Weather Data**

Weather is a key explanatory variable in the electric forecast models. The weather dataset from NOAA's National Climatic Data Center ("NCDC") contains temperature (maximum, minimum, and average), heating degree days ("HDD"), and cooling degree days ("CDD") for each day and weather station over the past 20+ years. This data is used to create (a) a historical weather series by billing period, (b) a forecast of "normal" weather by billing period.[6] Each of these processes is summarized below.

3.1.1 **Historical Weather by Billing Period**

The process used to create the historical weather series by billing period consists of the following steps:

1. Using historical daily weather data from the NCDC, sum the HDD and CDD values by billing portion. Each historical billing period consists of 20 portions. The Companies' historical meter reading schedule contains the beginning and ending date for each billing portion.
2. Average the billing portion total HDDs and CDDs by billing period.

3.1.2 **Normal Weather by Billing Period**

The Companies' process to produce its forecast of normal weather by billing period starts with producing a daily forecast of normal weather.[7] The Companies' process for developing its daily forecast (summarized below in Steps 2-5) is consistent with the process the NCDC uses to create its daily normal weather forecast.[8] The Companies' process to create its forecast of normal weather by billing period consists of six steps:

1. Compute the forecast of normal monthly weather by *calendar* month by averaging monthly degree-day values over the period of history upon which the normal forecast is based. The normal weather forecast is based on the most recent 20-year historical period. Therefore, the normal HDD value for January is the average of the 20 January HDD values in this period.
2. Compute "unsmoothed" daily normal weather values by averaging temperature, HDDs, and CDDs by calendar day. The unsmoothed normal temperature for January 1st, for example, is computed as the average of the 20 January 1st temperatures in the historical period. This process excludes February 29.
3. Smooth the daily values using a 30-day moving average centered on the desired day. The "smoothed" normal temperature for January 1st, for example, is computed as the average of the

[6] "Normal" weather is defined as the average weather over a 20-year historical period. The Companies do not attempt to forecast any trends in weather.

[7] Weather data in the electric forecast is taken from the weather stations at the Louisville Muhammad Ali International Airport (LG&E), Blue Grass Airport (KU), and Tri-Cities Airport (ODP).

[8] The NCDC derives daily normal values by applying a cubic spline to a specially prepared series of the monthly normal values.

unsmoothed daily normal temperatures between December 16th and January 15th.

4. Manually adjust the values in Step 3 so that the following criteria are met:
    1. The sum of the daily HDDs and CDDs by month should match the normal monthly HDDs and CDDs in Step 1.
    2. The daily temperatures and CDDs should be generally increasing from winter to summer and generally decreasing from summer to winter. The daily HDD series should follow a reverse trend.

    These criteria ensure the daily normal series is consistent with the monthly normal series.
5. Sum the HDD and CDD values by billing portion. The Companies' forecast meter reading schedule contains the beginning and ending date for each billing portion through the end of the forecast period. Use only historical weather that has actually occurred on February 29th when billing portions include leap days.
6. Average the billing portion totals by billing period.

4 Forecast Models

LG&E and KU's electricity sales forecasts are developed primarily through econometric modeling of energy sales by rate class, but also incorporate specific intelligence on the prospective energy requirements of the utilities' largest customers. Econometric modeling captures the observed statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely accepted approach can readily accommodate the influences of national, regional, and local (service territory) drivers of electricity sales. This approach may be applied to forecast the number of customers, energy sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service.

The LG&E sales forecast comprises one jurisdiction: Kentucky-retail. The KU sales forecast comprises three jurisdictions: Kentucky-retail, Virginia-retail (served by KU in Virginia as Old Dominion Power Company, "ODP"), and FERC-wholesale.[9] Within the retail jurisdictions, the forecast typically distinguishes several classes of customers including residential, commercial, public authority, and industrial.

The econometric models used to produce the forecast must pass two critical tests. First, the explanatory variables of the models must be theoretically appropriate and widely used in electricity sales forecasting. Second, the inclusion of these explanatory variables must produce statistically significant results that lead to an intuitively reasonable forecast. In other words, the models must be theoretically and empirically robust to explain the historical behavior of the Companies' customers. These forecast models are discussed in detail in the following sections.

4.1 Residential Forecasts

The Companies develop a residential forecast for each service territory. For the KU and LG&E (also referred to herein as "LE") service territories, the residential forecast includes all customers on the Residential Service ("RS"), Residential Time of Day ("RTOD"), and Volunteer Fire Department ("VFD") rate schedules. The ODP (also referred to herein as "OD") Residential forecast includes all customers on the RS rate schedule.[9] Residential sales are forecast for each service territory as the product of a customer and a use-per-customer forecast. See Table 2 for a summary:

[9] For the purposes of this document, the KU service territory comprises KU's Kentucky-retail and FERC-wholesale jurisdictions. The ODP service territory comprises the Virginia-retail jurisdiction.

Table 2: Residential Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_RS	KU Residential Service KU Residential Time-of-Day Energy Service KU Residential Time-of-Day Demand Service KU Volunteer Fire Department	Customers, Energy, Billed Demand
LE_RS	LE Residential Service LE Residential Time-of-Day Energy Service LE Residential Time-of-Day Demand Service LE Volunteer Fire Department	Customers, Energy, Billed Demand
OD_RS	OD Residential Service	Customers, Energy

4.1.1 Residential Customer Forecasts

The number of residential customers is forecast by service territory as a function of the number of forecast households or population in the service territory. Household and population data by county and Metropolitan Statistical Area ("MSA") is available from S&P Global.

4.1.2 Residential Use-per-Customer Forecasts

Average use-per-customer is forecast using a Statistically-Adjusted End-Use ("SAE") Model. The SAE model combines econometric modeling with traditional end-use modeling. The SAE approach defines energy use as a function of energy used by heating, cooling, and other equipment.

Use-per-Customer = a1*XHeat + a2*XCool + a3*XOther

Inputs for developing the heating, cooling, and other variables include weather (HDDs and CDDs), appliance saturations, efficiencies, and economic and demographic variables such as income, population, members per household, and electricity prices. Once the historical profile of these explanatory variables has been established, a regression model is specified to identify the statistical relationship between changes in these variables and changes in the dependent variable, use-per- customer. A more detailed discussion of each of these components and the methodology used to develop them is contained in Appendix B.

The load forecast uses EIA/Itron inputs that are projections of end-use efficiencies and adjusted electric space heating saturations over time. It is very difficult to determine which reductions in the history occurred because of DSM programs and which occurred because of customer-initiated efficiency gains. Because of this, historical data used in the residential and general service models is not adjusted for previous or current non-dispatchable demand side management and energy efficiency ("DSM-EE") programs, so the forecasts incorporate both customer-initiated energy efficiency in addition to impacts of utility DSM programs moving forward.

Through rebates, tax incentives, or credits, the Inflation Reduction Act ("IRA") is another mechanism to accelerate energy efficiency. The IRA is incorporated in the EIA/Itron projections of end-uses.

4.2 Commercial and Industrial Forecasts

Table 3 and Table 4 list the rate schedules included in the commercial and industrial forecasts. A relatively small number of the Companies' largest industrial customers account for a significant portion of total industrial sales, and any economic development opportunities, expansion, or reduction in operations by these customers can significantly impact the Companies' load forecast. Because of this, sales are forecast based on information obtained through direct discussions with these customers, their key account managers, and the economic development team. During these discussions, the customers are given the opportunity to review and comment on the usage and billed demand forecasts that the Companies create for them. This first-hand knowledge of the utilization outlook for these companies allows the Companies to directly adjust sales expectations. The following sections summarize the Companies' commercial and industrial forecasts.

Table 3: Commercial Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_GS	KU General Service single-phase service KU General Service three-phase service KU General Time-of-Day Energy single-phase service KU General Time-of-Day Energy three-phase service KU General Time-of-Day Demand single-phase service KU General Time-of-Day Demand three-phase service	Customers, Energy
LE_GS	LE General Service single-phase service LE General Service three-phase service LE General Time-of-Day Energy single-phase service LE General Time-of-Day Energy three-phase service LE General Time-of-Day Demand single-phase service LE General Time-of-Day Demand three-phase service	Customers, Energy
OD_GS	OD General Service single-phase service OD General Service three-phase service	Customers, Energy
KU_AES	KU All Electric School single-phase service KU All Electric School three-phase service	Customers, Energy
OD_SS	OD School Service[10]	Customers, Energy, Billed Demand
KU_Sec	KU Power Service Secondary KU Time-of-Day Secondary Service	Customers, Energy, Billed Demand
LE_Sec	LE Power Service Secondary LE Time-of-Day Secondary Service	Customers, Energy, Billed Demand
OD_Sec	OD Power Service Secondary OD Time-of-Day Secondary Service	Customers, Energy, Billed Demand

[10] OD School Service rate is a collection of six smaller rates, which are OD School Service General Service Single-Phase, OD School Service General Service Three-Phase, OD School Service Power Service Primary, OD School Service Power Service Secondary, OD School Service Time-of-Day Primary Service, and OD School Service Time-of-Day Secondary Service.

Table 4: Industrial Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_Pri	KU Power Service Primary KU Time-of-Day Primary Service	Customers, Energy, Billed Demand
LE_Pri	LE Power Service Primary LE Time-of-Day Primary Service	Customers, Energy, Billed Demand
OD_Ind	OD Retail Transmission Service OD Time-of-Day Primary Service	Customers, Energy, Billed Demand
OD_PS_Pri	OD Power Service Primary	Customers, Energy, Billed Demand
KU_RTS	KU Retail Transmission Service	Customers, Energy, Billed Demand
LE_RTS	LE Retail Transmission Service	Customers, Energy, Billed Demand
KU_FLS	KU Fluctuating Load Service	Customers, Energy, Billed Demand
OD_FWP	OD Water Pumping Service	Customers, Energy

4.2.1 General Service Forecasts

The general service forecasts include all customers on the GS rate schedule. For each service territory, GS forecasts employ an SAE model like the model used to forecast residential use-per- customer. The main difference between the GS and RS forecast is that the GS model forecasts total sales (rather than use-per-customer) as a function of energy used by heating, cooling, and other equipment, as well as binary variables to account for anomalies in the historical data.[11] A more detailed discussion of this model is included in Appendix A.

As discussed in the Residential UPC forecast (Section 4.1.2), commercial end-use inputs incorporate impacts of the IRA. There were no space heating adjustments for commercial customers.

4.2.2 KU Secondary Forecast

The KU Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, end-use intensity projections, and binary variables that account for anomalies in the historical data.

4.2.3 KU All-Electric School Forecast

The KU All-Electric School forecast includes all customers on the AES rate schedule. Sales to these customers are modeled as a function of end-use intensity projections, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.

4.2.4 ODP School Service Forecast

The ODP School Service forecast includes all customers on the SS rate schedule. Sales to these customers

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[11] A binary variable is a variable that can only take on two possible values, e.g., 0 and 1. Coding historically anomalous data using a binary variable allows it to be excluded from modeling, which improves model specification and thus model predictions. For example, in some models, the periods affected by the Covid-19 pandemic are coded as “1” and unaffected periods are coded as “0.” This coding effectively removes the significant impact of Covid-19 in a few historical months.

are modeled as a function of a constant, a variable to capture energy efficiency trends, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.

4.2.5 LG&E Secondary Forecast

The LG&E Secondary forecast includes all customers who receive secondary service on the PS rate schedule and all customers on the TODS rate schedule. Sales to these customers are modeled as a function of weather, economic variables, end-use intensity projections, and other binary variables to account for anomalies in the historical data.

4.2.6 LG&E Special Contract Forecast

LG&E has one customer that is served under a special contract. This customer's consumption is forecast separately based on information obtained through direct discussions with the customer.

4.2.7 ODP Secondary Forecast

The ODP Secondary forecast includes customers on the Power Service Secondary and Time-of-Day Secondary rate schedules. Sales to these customers are modeled as a function of energy used by heating equipment, cooling equipment, and other equipment as well as economic variables and other binary variables to account for anomalies in the historical data.

4.2.8 ODP Municipal Pumping Forecast

The ODP municipal pumping forecast consists of customers on the Water Pumping Service rate schedule. Sales to these customers are modeled using a trend based on recent sales.

4.2.9 KU Primary Forecast

The KU Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an economic variable, monthly binaries, and a binary variable to capture Covid-related usage changes. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers in these rate classes that are forecast individually based on information obtained through direct discussions with these customers.

4.2.10 KU Retail Transmission Service Forecast

The KU Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for several large KU RTS customers are forecast individually based on information obtained through direct discussions with these customers. The majority of the remaining RTS customers are mining customers. Sales to these customers are modeled as a function of a mining index, an economic variable, a lag dependent variable, and a binary variable to capture Covid-related usage changes.

4.2.11 KU Fluctuating Load Service Forecast

The KU Fluctuating Load Service forecast includes the one customer on the FLS rate schedule and is developed based on information obtained through direct discussions with this customer.

4.2.12 LG&E Primary Forecast

The LG&E Primary forecast includes all customers who receive primary service on the PS rate schedule and all customers on the TODP rate schedule. Sales to these customers are modeled as a function of an economic variable and monthly binaries. If necessary, the forecast is adjusted to reflect significant expansions or reductions for large customers on these rate schedules that are forecast individually based on information obtained through direct discussions with these customers.

4.2.13 LG&E Retail Transmission Service Forecast

The LG&E Retail Transmission Service forecast includes customers who receive service on the RTS rate schedule. Sales for several large LG&E RTS customers are forecast individually based on information obtained through direct discussions with these customers. Sales to the remaining customers are modeled as a function of historical monthly usage.

4.2.14 ODP Industrial Forecast

The ODP industrial forecast includes all customers receiving primary service on the PS rate schedule as well as customers receiving service on the TODP or RTS rate schedules. ODP industrial sales are modeled as a function of mining production forecasts and a weather variable.

4.3 KU Municipal Forecasts

KU's municipal customers develop their own sales forecasts. These forecasts are reviewed by KU for consistency and compared to historical sales trends. KU directs questions, concerns, and potential revisions to the municipal customers. See Table 5 for a summary:

Table 5: KU Municipal Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_MuniPri	KU Wholesale (Bardstown)	Energy, Billed Demand
KU_MuniTran	KU Wholesale (Nicholasville)	Energy, Billed Demand

4.4 Lighting and EV Charging Forecasts

The Lighting and EV Charging forecasts include customers receiving service on the following rate schedules in Table 6:

Table 6: Lighting and EV Charging Forecast Models and Rates

Forecast Model	Rate	Billing Determinants
KU_EV Fast Charging	KU Electric Vehicle Fast Charging Service	Energy
KU_EV Charging	KU Electric Vehicle Charging Service	Energy
KU_LES	KU Lighting Energy Service	Energy
KU_OSL	KU Outdoor Sports Lighting Service	Customers, Energy, Billed Demand
KU_TES	KU Traffic Energy Service	Customers, Energy
KU_UM	KU Unmetered Lighting Service	Customers
LE_EV Fast Charging	LE Electric Vehicle Fast Charging Service	Energy
LE_EV Charging	LE Electric Vehicle Charging Service	Energy
LE_LES	LE Lighting Energy Service	Energy
LE_OSL	LE Outdoor Sports Lighting Service	Customers, Energy, Billed Demand
LE_TES	LE Traffic Energy Service	Customers, Energy
LE_UM	LE Unmetered Lighting Service	Customers
OD_UM	OD Unmetered Lighting Service	Customers

All Lighting and EV Charging energy is modeled using a trend based on recent sales.

4.5 Distributed Solar Generation Forecast

The net metering distributed solar generation forecast is based on a consumer choice model. The consumer choice model is driven by various economic and financial inputs, including the retail price for electricity, the levelized cost of energy ("LCOE") for solar installations, disposable personal income, monthly binaries, and the price paid for energy exported to the grid. The changes to the timing of the solar investment tax credit ("ITC") phase-out discussed in the IRA is included in the LCOE variable in this model. Two models are specified using the above variables to create both a near- term and a long-term model. This forecast is a blend of the output of these two models.

In addition to net metering, there is also a forecast of behind-the-meter ("BTM") qualifying facilities ("QF") customers. This forecast contemplates only BTM QF and not independent or merchant generators that may locate to the area. This model is based upon the historical trend in BTM QF adoptions as well as current capacity-per-installation levels.

For purposes of revenue forecasting, the reduced sales attributable to distributed generation are allocated by rate as a reduction to the respective rate forecasts. The hourly distributed generation forecast, which is represented as negative load, is added on top of the mid load forecast hourly shape discussed in Section 5.2.

4.6 Electric Vehicle Forecast

The electric vehicle forecast is based on a consumer choice model. The consumer choice model is driven by the cost difference between electric vehicles and internal combustion engine vehicles. The forecast assumes the tax credits discussed in the IRA. Consistent with previous filings, efficiency and miles driven assumptions are used to translate the vehicles-in-operation into an energy impact and that impact is allocated entirely to the Residential class.

For purposes of revenue forecasting, the EV sales forecast is allocated as an increase to the RS forecasts. The EV hourly profile, which assumes managed charging, is added on top of the mid load forecast hourly profile discussed in Section 5.2.

An additional, positive adjustment was made to account for National Electric Vehicle Infrastructure ("NEVI") funds that were discussed in the Infrastructure Investment and Jobs Act ("IIJA"). The forecast assumes EV fast chargers will locate in the service territory beginning in 2023 because of this legislation and grow over time. The TODS rates for LG&E and KU receive the adjustments. By 2028, these chargers are only forecast to add 2 GWh of load annually.

4.7 Advanced Metering Infrastructure ("AMI") Benefits

The forecast has two adjustments to account for the benefits AMI is anticipated to provide in terms of load reduction. These adjustments reduce load.

4.7.1 Conservation Voltage Reduction ("CVR")

CVR adjustments are phased in over time as AMI meters are deployed and the necessary distribution controls are installed. Beginning in 2030, the combined CVR adjustments reduce annual load by 205 GWh annually. Specifically, CVR reduces RS and GS sales. The adjustments are consistent with what was discussed in Exhibit LEB-3 in Case Nos. 2020-00349 and 2020- 00350.

4.7.2 **AMI ePortal Savings**

AMI ePortal savings are allocated to customers on rates that do not currently have access to interval data. This primarily includes RS, GS, KU AES, ODP SS, and PS rates. These are phased in as AMI meters are deployed and represent 0.35% of monthly sales reductions for the applicable rates upon full deployment. The adjustments are consistent with what was discussed in Exhibit LEB-3 in Case Nos. 2020-00349 and 2020-00350.

4.8 **Billed Demand Forecasts**

For most rates, regression models are developed to forecast billed demands primarily as a function of energy. For some rates, billed demand forecasts are developed by applying historical ratios of billed demand and energy to the energy forecast. For a given customer and month, tariff provisions can impact the relationship between billed demands and energy. For example, the base demand for a TODP customer is computed as the greater of several factors including the customer's contract capacity and highest measured demand for the preceding 11 billing periods. The Companies' forecasting process considers the potential impact of these factors on the overall forecasts. Base, peak, and intermediate demands for the Companies' largest customers are developed with input from the customer.

5 Data Processing

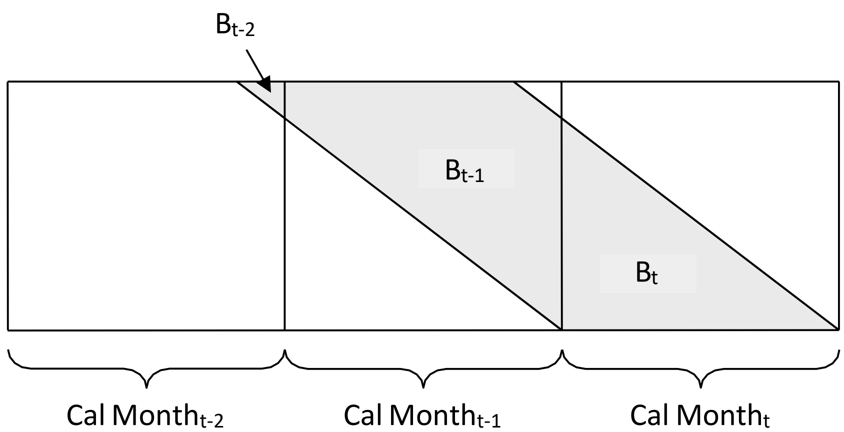
All customers are assigned to one of 20 billing portions. A billing portion determines what day of the month, generally, a customer's meter is read. Most customers' monthly bills include energy that was consumed in portions of more than one calendar month. This energy is referred to as "billed" energy and the majority of the Companies' forecast models are initially specified to forecast "billed" sales. The following processes are completed to prepare the forecasts for use as inputs to the Companies' revenue and generation forecasts:

- Billed-to-Calendar Energy Conversion
- Hourly Energy Requirements Forecast

5.1 Billed-to-Calendar Energy Conversion

Most forecast volumes must be converted from a billed to calendar basis to meet the needs of the Financial Planning department. The shaded area in Figure 2 represents a typical billing period (B). Area B_t represents the portion of billed energy consumed in the current calendar month (Cal $Month_t$). Area B_{t-1} represents the portion of billed energy consumed in the previous calendar month (Cal $Month_{t-1}$). Area B_{t-2} represents the portion of billed energy consumed in the calendar month two months prior to the current month (Cal $Month_{t-2}$). Not all billing periods include volumes that were consumed in the calendar month two months prior to the current month.

Figure 2: Billed and Calendar Energy



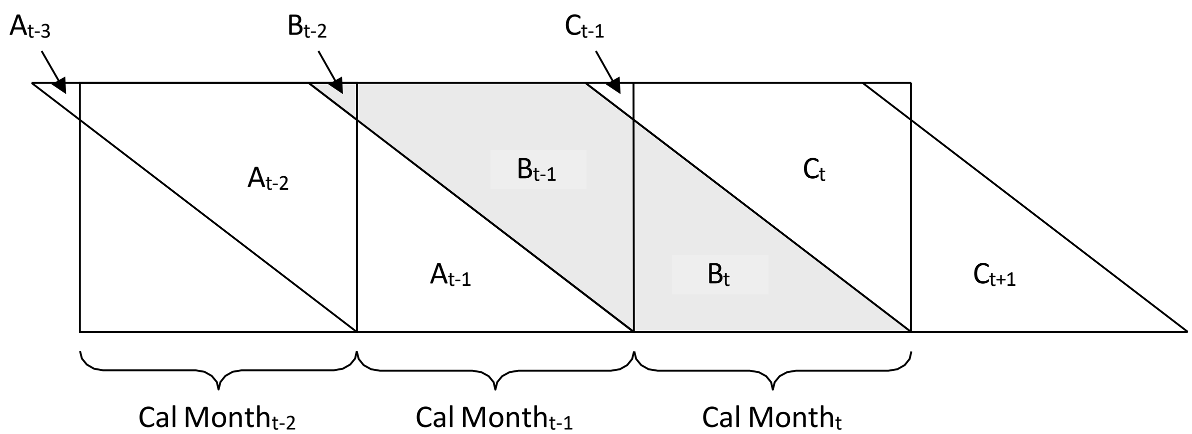
In this process, billed energy is allocated to calendar months based on when the energy is consumed. Furthermore, the weather-sensitive portion of the billed energy forecast is allocated to calendar months based on degree days (HDDs and CDDs) and the non-weather-sensitive portion is allocated based on billing days.[12] For example, the June billing period includes portions of June, May, and possibly April. Under normal weather conditions, June will have more CDDs than May. Therefore, a greater portion of the weather-

[12] For a given billing period, the number of degree days and billing days in each calendar month is computed as an average over the 20 billing portions.

sensitive energy in the June billing period will be allocated to the calendar month of June.

Figure 3 contains two additional billing periods (A & C). Calendar sales for Cal Month$_{t-1}$ is equal to the sum of energy in in billing period segments A_{t-1}, B_{t-1}, and C_{t-1}.

Figure 3 – Billed and Calendar Energy



5.2 Hourly Energy Requirements Forecast

5.2.1 Normal Hourly Energy Requirements Forecast

The Generation Planning department uses the hourly energy requirements forecast to develop resource expansion plans and a forecast of generation production costs. An hourly energy requirements forecast is developed for each company by adding losses to calendar-month sales and allocating the sum to hours in each month. The result reflects customers' hourly energy requirements under normal weather conditions. The following process is used to develop this forecast:

1. Sum calendar-month forecast volumes independent of distributed generation and incremental EV load by company. Then, add transmission and distribution losses as well as incremental company uses to compute monthly energy requirements. The sum of calendar-month forecast volumes for KU includes forecast volumes for the KU and ODP service territories.
2. Develop normalized load duration curves for each company and month based on 10 years of historical hourly energy requirements. For KU, to model the impact of the municipal departure, this process is completed based on historical energy requirements where the impact of the departing municipals has been removed.
3. Compute the ratio of hourly energy requirements and monthly energy requirements for each hour and company. Rank the ratios in each month from highest to lowest. The normalized load duration curves are computed by averaging the ratios by month, rank, and company.
    1. The winter and summer peak can occur in multiple months, and the predicted peak for a season (meaning winter or summer) is higher than the predicted peak for any individual month within the season. For this reason, the normalized load duration curves for January and August are adjusted to match peaks produced in separate seasonal models. This process produces seasonal peak demand forecasts that are placed within January (winter) and August (summer).

4. Allocate total forecast monthly energy requirements by company to hours using the normalized load duration curves. For KU, the normalized load durations curves reflect the municipal departure.
5. Assign hourly energy requirements to specific hours in each month based on the ordering of days and weekends in the month. Historical reference years and months having matching calendar profiles as the forecast month (e.g., a historical August that begins on a Tuesday) are selected to be used for ordering purposes only.
6. Adjust the hourly energy requirements forecast to reflect the hourly forecast impact of distributed solar generation, electric vehicle, and other inputs having distinct load shapes. Said differently, the profiles attributable to solar, electric vehicles, and economic development are layered in separately. The solar profiles are developed to ensure that the underlying weather and solar irradiance align. Consistent with prior forecasts, EV managed charging is assumed for the hourly shape.

5.2.2 Weather-Year Forecasts

The Companies develop their hourly energy requirements forecast with the assumption that weather will be average or "normal" in every year (see discussion above in Section 5.2.1). While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. For this reason, to support the Companies' Reserve Margin Analysis and other studies focused on generation reliability, the Companies produce 51 hourly energy requirement forecasts for each year of the forecast based on actual weather in each of the last 51 years (1973 through 2023).

To create these "weather year" forecasts, the Companies develop a model to forecast hourly energy requirements as a function of temperature and calendar variables such as day of week and holidays. This model is used to forecast hourly energy requirements in each year of the forecast period based on hourly temperatures from the prior 51 calendar years but using calendar variables from the forecast period. The Companies produce two version of this analysis; a version where the forecast years are all identically shaped from a calendar perspective (i.e. all years start on a Sunday and leap days are excluded), and a version where forecast years match the calendar as it actually occurs. These two versions rely on identical modeling and weather, but are used for different purposes. The former version allows for a consistent load distribution across multiple years and is useful for analysis such as assessing reserve margin requirements, while the latter allows for accurate assessment of weather likelihood and is useful for analysis of minimum fuel burn requirements and outage planning. To ensure consistency with the Companies' energy forecast, the following steps are taken once the model outputs are available:

1. All hours of the weather year forecast are adjusted so that the mean of monthly energy requirements from the weather year forecasts equals monthly energy requirements in the mid energy forecast excluding those inputs having distinct load shapes.
2. Extreme points in the historical data are reviewed individually to ensure model predictions are reasonable based on recent experiences and knowledge of the Company's system load response. These points can be increased or decreased incrementally as appropriate.
3. At this point, inputs having distinct load shapes are added (or subtracted) on an hourly basis. These include EV charging, distributed generation, and new major accounts.
    a. The hourly distributed generation profiles are layered in according to each weather year. For historical years for which we have solar irradiance data (since 1998), the distributed generation profile matches that year's weather profile. For prior years, the distributed

generation profile represents an average irradiance of the years that are available.

4. All hours of the weather year forecast are again adjusted, but this time so that the mean of monthly energy requirements from the weather year forecasts equals monthly energy requirements in the mid energy forecast including those load forecast inputs having distinct load shapes.
5. The mean of the seasonal peaks of the weather years are then adjusted to match the seasonal peaks forecast using normal weather.[13]
6. Finally, all hours of the weather year forecast are adjusted so that the mean of seasonal energy requirements from the weather year forecasts equals seasonal energy requirements in the mid energy forecast, which include those load forecast inputs having distinct load shapes.

[13] Seasons are defined as winter (November, December, January, February), summer (June, July, August, September), and shoulder (March, April, May, October) in this context.

6 Review

In addition to assessing the reasonableness of models (discussed in introduction to Section 4), forecast results are visually inspected versus recent history and prior forecasts to ensure reasonableness of results. Because of the obligation to serve load in every hour, the Companies ensure monthly and hourly profiles are reasonable. To accomplish this, the new forecast is compared to (i) the previous forecast, (ii) weather-normalized actual sales for the comparable period in prior years, (iii) a range of historical actual sales and energy requirements, and (iv) the end-use projections assumed in the forecast models. This process ensures that the forecast is consistent with recent trends in the way customers are using electricity today and how that could change in the future.

2024 IRP Inflation Assumptions

Background

In recent analyses, including the 2021 IRP and 2022 CPCN, the Companies used a 2.0 percent forecast for inflation, informed by the stated mission of the Federal Reserve ("Fed"), recent historical data, and market expectations of inflation.

Beginning in 2021, inflation measures began increasing well beyond the 2.0 percent expectation. At that time, the Fed – the chief agency responsible for managing inflation – believed this inflation to be short-lived or transitory. Fed Chair Jerome Powell on August 27, 2021:

> *The spike in inflation is so far largely the product of a relatively narrow group of goods and services that have been directly affected by the pandemic and the reopening of the economy. Durable goods alone contributed about 1 percentage point to the latest 12-month measures of headline and core inflation. Energy prices, which rebounded with the strong recovery, added another 0.8 percentage point to headline inflation, and from long experience we expect the inflation effects of these increases to be transitory. In addition, some prices—for example, for hotel rooms and airplane tickets—declined sharply during the recession and have now moved back up close to pre-pandemic levels. The 12-month window we use in computing inflation now captures the rebound in prices but not the initial decline, temporarily elevating reported inflation. These effects, which are adding a few tenths to measured inflation, should wash out over time.*[1]

The view of 'transitory' inflation supported continued use of 2.0 percent as a long-term inflation forecast. However, inflation continued to climb in 2022 and remains above the Fed's stated goal of 2.0 percent.

Question

What is the appropriate value to use for long-term inflation forecasts in the 2024 IRP?

Analysis

To determine the appropriate inflation assumption, the Companies evaluated inflation across three measures: policymakers' goals, recent historical data, and market expectations.

Policymakers' Goals

The Fed is on record stating the official inflation target is 2.0 percent. A Federal Open Market Committee press release on January 25, 2012 stated:

> *The inflation rate over the longer run is primarily determined by monetary policy, and hence the Committee has the ability to specify a longer-run goal for inflation. The Committee judges that inflation at the rate of 2 percent, as measured by the annual change in the price index for personal consumption expenditures, is most consistent over*

[1] https://www.federalreserve.gov/newsevents/speech/powell20210827a.htm

the longer run with the Federal Reserve's statutory mandate. Communicating this inflation goal clearly to the public helps keep longer-term inflation expectations firmly anchored, thereby fostering price stability and moderate long-term interest rates and enhancing the Committee's ability to promote maximum employment in the face of significant economic disturbances.[2]

The Fed's goal of 2.0 percent inflation was reiterated on the Fed's FAQ from a post on August 27, 2020; however, the Fed noted that after periods of sub-2 percent inflation, it might be prudent to manage inflation modestly above 2 percent:

> *Why does the Federal Reserve aim for inflation of 2 percent over the longer run? The Federal Open Market Committee (FOMC) judges that inflation of 2 percent over the longer run, as measured by the annual change in the price index for personal consumption expenditures, is most consistent with the Federal Reserve's mandate for maximum employment and price stability. When households and businesses can reasonably expect inflation to remain low and stable, they are able to make sound decisions regarding saving, borrowing, and investment, which contributes to a well-functioning economy.*
>
> *For many years, inflation in the United States has run below the Federal Reserve's 2 percent goal. It is understandable that higher prices for essential items, such as food, gasoline, and shelter, add to the burdens faced by many families, especially those struggling with lost jobs and incomes. At the same time, inflation that is too low can weaken the economy. When inflation runs well below its desired level, households and businesses will come to expect this over time, pushing expectations for inflation in the future below the Federal Reserve's longer-run inflation goal. This can pull actual inflation even lower, resulting in a cycle of ever-lower inflation and inflation expectations.*
>
> *If inflation expectations fall, interest rates would decline too. In turn, there would be less room to cut interest rates to boost employment during an economic downturn. Evidence from around the world suggests that once this problem sets in, it can be very difficult to overcome. To address this challenge,* ***following periods when inflation has been running persistently below 2 percent, appropriate monetary policy will likely aim to achieve inflation modestly above 2 percent for some time****. By seeking inflation that averages 2 percent over time, the FOMC will help to ensure longer-run inflation expectations remain well anchored at 2 percent.*[3]

Fed Chair Jerome Powell has reiterated the 2.0 percent target on numerous occasions, including as recently as August 25, 2023.[4]

Recent Historical Data

There are many measures of inflation, with two key measures being the national consumer price index ("CPI") and the Personal Consumption Expenditures ("PCE") price index. As stated in the Fed's

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[2] https://www.federalreserve.gov/newsevents/pressreleases/monetary20120125c.htm
[3] https://www.federalreserve.gov/faqs/economy_14400.htm (emphasis added).
[4] https://www.federalreserve.gov/newsevents/speech/powell20230825a.htm

comments above, the Fed's target is measured against the PCE; however, the CPI is more commonly referenced in the financial press and is the basis for many contract escalation rates.[5] Historically, the two indices are highly correlated, with the CPI averaging roughly 0.2 percentage points higher than the PCE over the past 15 years and 0.5 percentage points higher over the past 30 years (see Table 1).

Table 1: CPI-U and PCE Inflation (1993-2023)[6]

Year	CPI-U Annual Average	CPI-U YoY Inflation Rate (%)	PCE Annual Average	PCE YoY Inflation Rate (%)
1993	144.5	--	794.5	--
1994	148.2	2.6%	812.3	2.2%
1995	152.4	2.8%	830.0	2.2%
1996	156.9	3.0%	845.7	1.9%
1997	160.5	2.3%	860.6	1.8%
1998	163.0	1.6%	871.6	1.3%
1999	166.6	2.2%	883.0	1.3%
2000	172.2	3.4%	898.8	1.8%
2001	177.1	2.8%	915.8	1.9%
2002	179.9	1.6%	931.1	1.7%
2003	184.0	2.3%	946.1	1.6%
2004	188.9	2.7%	964.8	2.0%
2005	195.3	3.4%	985.9	2.2%
2006	201.6	3.2%	1,009.5	2.4%
2007	207.3	2.8%	1,032.0	2.2%
2008	215.3	3.9%	1,052.3	2.0%
2009	214.5	-0.4%	1,062.0	0.9%
2010	218.1	1.7%	1,077.4	1.4%
2011	224.9	3.1%	1,094.5	1.6%
2012	229.6	2.1%	1,114.8	1.8%
2013	233.0	1.5%	1,131.4	1.5%
2014	236.7	1.6%	1,148.4	1.5%
2015	237.0	0.1%	1,162.5	1.2%
2016	240.0	1.3%	1,181.1	1.6%
2017	245.1	2.1%	1,200.0	1.6%
2018	251.1	2.4%	1,222.8	1.9%
2019	255.7	1.8%	1,242.9	1.6%
2020	258.8	1.2%	1,259.3	1.3%
2021	271.0	4.7%	1,304.8	3.6%
2022	292.7	8.0%	1,373.2	5.2%
2023	304.7	4.1%	1,429.5	4.1%
15-Year CAGR		2.3%		2.1%
30-Year CAGR		2.5%		2.0%

[5] The "headline" inflation number is generally considered to be the CPI-U, which reflects the CPI for all urban customers.

[6] Data sources: https://fred.stlouisfed.org/series/CPIAUCSL and https://fred.stlouisfed.org/series/PCEPILFE

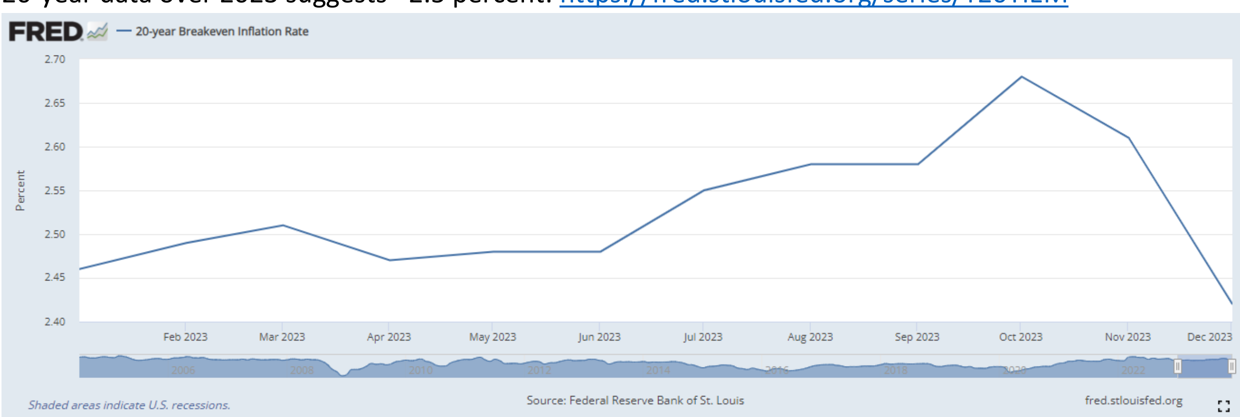
Focusing on the most recent 15-year (consistent with the IRP analysis period) and 30-year (consistent with the Companies' long-term resource planning evaluations) periods, the CPI-U reflects average annual inflation of 2.3 percent and 2.5 percent, respectively.

Market Expectations

While the market doesn't have an explicit measure of inflation expectations, an implicit measure can be found through the TIPS spread. The TIPS spread is the comparison of the yield between standard US treasuries and Treasury Inflation-Protected Securities ("TIPS"), which are adjusted for inflation. In a rational market, investors would buy and sell these securities to account for arbitrage opportunities until the spread matched their view of inflation. The Fed refers to this as the "breakeven inflation rate" over various terms.[7] The 10-year, 20-year, and 30-year treasuries can be used as proxies to evaluate inflation expectations over those timeframes.

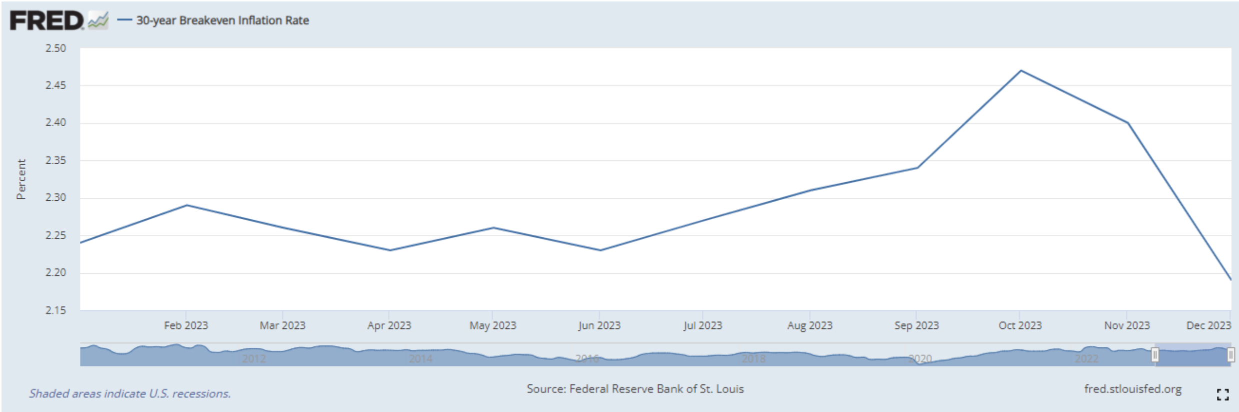
10-year data over 2023 suggests ~2.3 percent: https://fred.stlouisfed.org/series/T10YIEM

20-year data over 2023 suggests ~2.5 percent: https://fred.stlouisfed.org/series/T20YIEM



[7] TIPS are adjusted based on the CPI, so the breakeven inflation rate is a measure of CPI inflation.

30-year data over 2023 suggests ~2.3 percent: https://fred.stlouisfed.org/series/T30YIEM



Summary and Conclusions

The Fed's inflation target is 2.0 percent. Recent historical data suggests inflation of 2.3 percent (over the past 15 years) to 2.5 percent (over the past 30 years). The market expectations for inflation based on the TIPS spread range between 2.3 and 2.5 percent.

Based on this data, inflation estimates range between 2.0 and 2.5 percent, and a reasonable middle ground would be to use 2.3 percent to forecast long-term inflation.