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2024 California Gas Report

Workpapers

Prepared by
Pacific Gas and Electric Company

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2024 California Gas Report

Workpapers

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Introduction

I. Introduction

The 2024 California Gas Report (CGR) presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2040. This document contains the workpapers for the Northern California portion of the **2024 California Gas Report**. The workpapers detail important forecast assumptions and data that supports the outlook. The forecast assumptions were developed jointly by the California Public Utilities Commission designated respondent utilities – Pacific Gas and Electric Company, San Diego Gas & Electric Company, and the Southern California Gas Company. The joint utilities developed these assumptions to provide a consistent, statewide outlook for natural gas requirements. These workpapers have been prepared by Pacific Gas and Electric Company (PG&E) in compliance with the request by the California Public Utilities Commission dated September 13, 1973.

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Annual Requirements

II. Annual Requirements

A. Introduction to the Gas Demand Forecast Workpapers

PG&E uses econometric models to predict some of its natural gas demand, adjusted for the impact of climate change, energy efficiency and building electrification. Other parts of total demand are forecast by using market information. For the econometric models, the first step is to identify a causal relationship between the variable to be forecast and the variables believed to influence its movements. The choice of explanatory variables is based in economic theory. Once the determinants of energy use are identified, data for the variables are collected and a functional form is specified.

Various formulations are tested to find one that conforms to the theoretical foundation, has sound statistical properties, and produces a reasonable forecast. For the 2024 California Gas Report (CGR), PG&E has utilized maximum likelihood regression models, with time series terms on the residuals to address serial autocorrelation in the residuals, to predict residential, small commercial, large commercial/industrial distribution, industrial transmission demand, and industrial backbone level demand (shown in Section II-B of these workpapers). These models attempt to isolate the effects of slow-moving drivers, such as economics, demographics, and appliance and building shell efficiency, along with fast moving drivers, such as temperature, to produce forecasts of sectoral gas demand. Demand forecast from the econometric models is obtained by simulating the models using forecasts of the exogenous variables.

PLEXOS is a Microsoft Windows-based software package that solves, by iteration, a system of simultaneous equations describing a market with supplies, demands, and transmission routes. PLEXOS has been widely used by the industry to model electric, water, gas, and renewable markets. Marketing information about PLEXOS is available at the vendor's web site, https://www.energyexemplar.com/products/plexos. These two classes of forecasts are then combined with forecasts obtained exogenously (wholesale, Natural Gas Vehicle, inter-departmental, Southwest Exchange Gas Delivery Agreement) to produce the PG&E on-system demand forecast.

The forecast horizon is 2024 through 2040.

Gas demand forecasts under various demand scenarios are presented in Section II.D.

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II.B. Econometric Models

B. Econometric Models

Table 1

Abbreviation	Model(s)	Description
POP_PGE	Residential Customer	Population Growth for the PG&E territory area. (Moody's Analytics (December 2021))
HH_PGE	Residential Customer	Number of households in the PG&E territory. (Moody's Analytics (December 2021))
January-November	Residential Customer, Residential, Small Commercial Customer, Small Commercial, Large Commercial, GNTBB, GNTD, GNTT, GNR1 Interdepartmental	Monthly binary dummy variables to account for seasonality in usage not due to temperature.
Rescounts	Residential Customer, Small Commercial Customer	Total number of active residential customers in the PG&E territory.
Per_customer_usage	Residential	Total residential usage divided by the number of customers.
post78_stationary	Residential	The percentage of households built after 1978 when energy efficiency became more important. This is also used as an energy efficiency index. (Moody's Analytics (December 2021))
Gas_price_res	Residential	Real residential gas rate and commodity costs.
Drought_JAN14	Residential	Binary dummy variable to account for customer behavior change due to the drought.
HDD_1in2	Residential Customer, Residential, Small Commercial Customer, Small Commercial, Large Commercial, GNTD, GNR1 Interdepartmental	Monthly total system composite heating degree days (base temperature 60 degrees F)
HDD_1in10	Residential Customer, Residential, Small Commercial Customer, Small Commercial, Large Commercial, GNTD	Monthly or quarterly total system composite heating degree days (base temperature 60 degrees F). Forecast period represents 1 in 10 cold year conditions.
COVID	Residential Customer, Residential, Small Commercial Customer, Small Commercial, Large Commercial, GNTBB, GNTD, GNTT, GNR1 Interdepartmental	Binary dummy variable to account for customer behavior change due to COVID

Table 1 (continued)

Abbreviation	Model(s)	Description
SmComcounts	Small Commercial Customer	Total number of active small commercial customers in the PG&E territory.
Per_customer_usage	Small Commercial	Total small commercial usage divided by the number of customers.
Percent_ServiceEmployment2	Small Commercial	Percent of service sector employment (finance, information, service level) of total employment. (Moody's Analytics (December 2021))
LC_usage2	Large Commercial	Total usage to large commercial. (Monthly total MDTH)
Gas_price_LrgCom	Large Commercial	Real large commercial gas rate and commodity costs.
Percent_ServiceEmployment	Large Commercial (GNR2), GNTD	Percent of service level sector employment of total employment. (Moody's Analytics (December 2021))
GNTD_usage	GNTD	Total usage to distribution level industrial customers. (Monthly total MDTH)
Gas_price_GNTD_12mo	GNTD	Real industrial distribution gas rate and commodity costs 12 month moving average.
GNTT_USAGE	GNTT	Total usage to transmission level industrial customers. Monthly total MDTH)
GDP_DETAIL_4247_PGE	GNTT	Gross petroleum and petroleum products merchant wholesalers. (Moody's Analytics (December 2021)
Gas_price_GNTT_12mo	GNTT	Real industrial transmission gas rate and commodity costs 12 month moving average.
GNTBB_Counts	GNTBB	Total number of active GNTBB customers in the PG&E territory.
Gas_price_GNTBB_12mo	GNTBB	Real industrial backbone gas rate and commodity costs 12 month moving average.
GNTBB_USAGE	GNTBB	Total usage to backbone level industrial customers. (Monthly total MDTH)
GNR1_Interdepartmental_Usa	GNR1_Interdepartmental	Total usage to GNR1 Interdepartmental. (Monthly total MDTH)

RESIDENTIAL CUSTOMER EQUATION

Residential customer counts are forecast on a model employing historic data from 2010 through 2023. Monthly counts are forecast as a function of households, population, monthly dummy variables, and a first order autoregressive term to correct for any autocorrelation that may be present in the model errors; reducing potential bias in the econometric parameter estimates.

Table 2

Dependent Variable: Res_Counts
Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	1982278	382161	5.19	<.0001
POP_PGE	99.8829	36.2364	2.76	0.0066
HH_PGE	126.4031	87.0378	1.45	0.1485
January	3230	942.7233	3.43	0.0008
February	-2984	1173	-2.54	0.012
March	-2881	1333	-2.16	0.0322
April	-1906	1435	-1.33	0.1859
May	-1075	1492	-0.72	0.4721
June	-4397	1509	-2.91	0.0041
July	-2465	1487	-1.66	0.0995
August	-2122	1426	-1.49	0.1389
September	-3232	1320	-2.45	0.0155
October	-3098	1154	-2.69	0.008
November	1118	912.0455	1.23	0.2221
AR1	-0.8753	0.0835	-10.49	<.0001
AR2	-0.1235	0.085	-1.45	0.1482

SSE	1859327983	DFE	152
MSE	12232421	Root MSE	3497
SBC	3289.61554	AIC	3239.63212
MAE	2354.59026	AICC	3243.23477
MAPE	0.0553325	HQC	3259.91782
Log Likelihood	-1603.8161	Transformed Regression R-Square	0.457
Durbin-Watson	1.0054	Total R-Square	0.9988
		Observations	168

RESIDENTIAL DEMAND EQUATION

Residential usage is a forecast on a per customer basis using a model employing historic data from 2006 through 2023. The monthly forecast is a function of housing stock, real residential gas rate and commodity costs, PG&E system composite heating degree days, monthly dummy variables, drought dummy variable, and a first order autoregressive term to correct for any autocorrelation that may be present in the model errors; reducing potential bias in the econometric parameter estimates. The housing stock variable is the proportion of household added after 1978 when building efficiency standards went into effect in California; this reflects the influence of improvements in building shell and appliance efficiencies on residential gas demand over time.

Table 3

Dependent Variable: Per_customer_usage
Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	0.006382	0.000484	13.18	<.0001
HDD_1in2	0.0000131	4.2551E-07	30.81	<.0001
post78_stationary	-0.008192	0.001133	-7.23	<.0001
Gas_price_res	-0.000024	6.6511E-06	-3.63	0.0004
Drought_JAN14	0.0000297	0.0000538	0.55	0.5813
January	0.000492	0.0000504	9.76	<.0001
February	0.0000833	0.0000652	1.28	0.2029
March	-0.000499	0.0000844	-5.91	<.0001
April	-0.000798	0.000108	-7.38	<.0001
May	-0.000946	0.000131	-7.23	<.0001
June	-0.000967	0.000144	-6.73	<.0001
July	-0.001015	0.000149	-6.83	<.0001
August	-0.001022	0.000149	-6.85	<.0001
September	-0.001039	0.000145	-7.15	<.0001
October	-0.001125	0.000128	-8.81	<.0001
November	-0.000701	0.0000771	-9.09	<.0001
AR1	-0.3988	0.0653	-6.11	<.0001
Intercept	0.006382	0.000484	13.18	<.0001

SSE	6.14629E-06	DFE	199
MSE	3.08859E-08	Root MSE	0.0001757
SBC	-3048.4528	AIC	-3105.8326
MAE	0.00011951	AICC	-3102.7417
MAPE	3.16860336	HQC	-3082.651
Log Likelihood	1569.91629	Transformed Regression R-Square	0.9874
Durbin-Watson	1.9475	Total R-Square	0.9935
		Observations	216

SMALL COMMERCIAL CUSTOMER EQUATION

Small Commercial customer counts are forecast on a model employing historic data from 2006 through 2023. Monthly counts are forecast as a function of residential customer counts, monthly dummy variables, and autoregressive terms to correct for any autocorrelation that may be present in the model errors.

Table 4

Dependent Variable: SmComcounts

Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	-8453	-24451	44604	-0.55
Rescounts	0.0557	0.0591	0.005099	11.6
January	516.6584	572.5719	66.2196	8.65
February	696.9288	768.406	88.9704	8.64
March	535.5418	595.3413	102.1906	5.83
April	239.8754	324.9145	110.2558	2.95
May	-349.3973	-227.7657	114.5492	-1.99
June	-710.8257	-550.5212	119.7393	-4.6
July	-1110	-943.8779	115.7321	-8.16
August	-1415	-1227	110.7684	-11.08
September	-1564	-1378	102.3796	-13.46
October	-1495	-1336	88.4928	-15.1
November	-808.6098	-729.8214	63.6365	-11.47
AR1	-358.5727	-0.9995	0.004043	-247.2

SSE	16032366.6	DFE	202
MSE	79368	Root MSE	281.72354
SBC	3117.55877	AIC	3070.30487
MAE	191.065684	AICC	3072.39443
MAPE	0.0848306	HQC	3089.39557
Log Likelihood	-1521.1524	Transformed Regression R-Square	0.7824
Durbin-Watson	1.0675	Total R-Square	0.9913
		Observations	216

SMALL COMMERCIAL DEMAND EQUATION

Small Commercial usage is a forecast on a per customer basis using a model employing historic data from 2004 through 2023. The monthly forecast is a function of employment index, PG&E system composite heating degree days, monthly dummy variables, and a first order autoregressive term to correct for any autocorrelation that may be present in the model errors; reducing potential bias in the econometric parameter estimates. The employment index variable is the proportion of service sector jobs divided by total jobs in the PG&E territory.

Table 5

Dependent Variable: Per_customer_usage
Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	0.032	0.004553	7.03	<.0001
HDD_1in2	0.000058	1.8965E-06	30.56	<.0001
Percent_ServiceEmployment2	-0.0186	0.008646	-2.16	0.0322
January	0.002375	0.000221	10.73	<.0001
February	0.00198	0.000315	6.27	<.0001
March	-0.000955	0.000419	-2.28	0.0238
April	-0.002408	0.000524	-4.6	<.0001
May	-0.003328	0.000622	-5.35	<.0001
June	-0.004088	0.000676	-6.05	<.0001
July	-0.004493	0.000696	-6.46	<.0001
August	-0.00428	0.000692	-6.18	<.0001
September	-0.003653	0.000665	-5.49	<.0001
October	-0.00311	0.000576	-5.4	<.0001
November	-0.001748	0.000337	-5.19	<.0001
AR1	-0.7138	0.0467	-15.28	<.0001

SSE	0.00018318	DFE	225
MSE	8.14124E-07	Root MSE	0.0009023
SBC	-2616.5536	AIC	-2668.7632
MAE	0.00062558	AICC	-2666.6204
MAPE	2.2425447	HQC	-2647.7266
Log Likelihood	1349.3816	Transformed Regression R-Square	0.974
Durbin-Watson	2.0507	Total R-Square	0.9911
		Observations	240

LARGE COMMERCIAL DEMAND EQUATION

Large commercial (GNR2) are forecast using a model employing historic data from 2006 through 2023. Monthly usage is modeled as a function of real large commercial gas rate and commodity prices, PG&E system composite heating degree days, employment index, monthly dummy variables, and a first order autoregressive term to correct for autocorrelation that may be present in the model errors; reducing potential bias in the econometric parameter estimates. The employment index variable is the proportion of service sector jobs divided by total jobs in the PG&E territory.

Table 6

Dependent Variable: LC_usage2
Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	966.6404	143.7355	6.73	<.0001
HDD_1in2	0.4527	0.0714	6.34	<.0001
Gas_price_LrgCom	0.8672	1.665	0.52	0.603
Percent_ServiceEmployment	-1098	299.7921	-3.66	0.0003
January	2.7477	8.4134	0.33	0.7443
February	16.2558	11.6372	1.4	0.164
March	1.8986	15.3488	0.12	0.9017
April	35.8106	19.7382	1.81	0.0711
May	36.3984	23.4583	1.55	0.1223
June	23.1191	25.4534	0.91	0.3648
July	19.1597	26.1202	0.73	0.4641
August	86.0625	26.0888	3.3	0.0011
September	158.2063	25.2365	6.27	<.0001
October	141.1515	21.9639	6.43	<.0001
November	57.3103	12.9104	4.44	<.0001
AR1	-0.6326	0.0555	-11.4	<.0001

SSE	198811.848	DFE	200
MSE	994.05924	Root MSE	31.52871
SBC	2173.66147	AIC	2119.65701
MAE	22.9859193	AICC	2122.39068
MAPE	3.76978565	HQC	2141.47494
Log Likelihood	-1043.8285	Transformed Regression R-Square	0.5968
Durbin-Watson	1.8652	Total R-Square	0.8099
		Observations	216

GNT DISTRIBUTION-LEVEL DEMAND EQUATION

Distribution level industrial (GNTD) usage is forecast using a model employing historic data from 2004 through 2023. Monthly usage is modeled as a function of real distribution level industrial gas rate and commodity prices, PG&E system composite heating degree days, employment index, monthly dummy variables, and a first order autoregressive term to correct for autocorrelation that may be present in the model errors; reducing potential bias in the econometric parameter estimates. The employment index variable is the proportion of service sector jobs divided by total jobs in the PG&E territory.

Table 7

Dependent Variable: GNTD_USAGE
Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	1312	475.0981	2.76	0.0062
HDD_1in2	1.9924	0.1796	11.09	<.0001
Percent_ServiceEmployment	988.2015	953.5374	1.04	0.3012
Gas_price_GNTD_12mo	1.2255	8.265	0.15	0.8823
January	89.4255	21.0347	4.25	<.0001
February	-38.458	29.9427	-1.28	0.2003
March	196.836	39.7769	4.95	<.0001
April	98.0127	49.6605	1.97	0.0497
May	119.2759	58.9769	2.02	0.0443
June	38.2782	64.0808	0.6	0.5509
July	63.1941	65.9242	0.96	0.3388
August	321.8605	65.6039	4.91	<.0001
September	291.8193	63.0555	4.63	<.0001
October	309.575	54.5723	5.67	<.0001
November	51.7263	31.9376	1.62	0.1067
AR1	-0.7139	0.0473	-15.09	<.0001

SSE	1645967.12	DFE	224
MSE	7348	Root MSE	85.72087
SBC	2889.46119	AIC	2833.77096
MAE	62.4906011	AICC	2836.21043
MAPE	2.94559898	HQC	2856.21006
Log Likelihood	-1400.8855	Transformed Regression R-Square	0.7813
Durbin-Watson	2.0141	Total R-Square	0.876
		Observations	240

GNT Transmission-Level Demand Equation

Transmission level industrial (GNTT) usages are forecast using a model which employs historic data from 2003 through 2023. Monthly usages are modeled as a function of Gross Domestic Product for the PG&E area for petroleum and petroleum products merchant wholesalers, real GNTT gas rate and commodity costs, monthly seasonal dummy variables, and a first and third order autoregressive term to correct for autocorrelation that may be present in the model errors; reducing potential bias in the econometric parameter estimates.

Table 8

Dependent Variable: GNTT_USAGE
Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	17090	4008	4.26	<.0001
GDP_DETAIL_4247_PGE	-0.5772	0.6646	-0.87	0.386
Gas_price_GNTT_12mo	-112.0663	112.8593	-0.99	0.3217
January	-247.2727	181.7015	-1.36	0.1749
February	-1850	222.0291	-8.33	<.0001
March	-908.0921	228.9052	-3.97	<.0001
April	-1334	240.9513	-5.54	<.0001
May	-762.4438	249.7247	-3.05	0.0025
June	-1073	251.6546	-4.26	<.0001
July	1230	249.276	4.93	<.0001
August	3866	239.8989	16.11	<.0001
September	3370	227.3247	14.82	<.0001
October	815.7835	220.2122	3.7	0.0003
November	-573.6414	178.36	-3.22	0.0015
AR1	-0.6831	0.0514	-13.3	<.0001
AR3	-0.1906	0.0527	-3.62	0.0004

SSE	138901197	DFE	236
MSE	588564	Root MSE	767.17951
SBC	4136.2779	AIC	4079.80704
MAE	580.126584	AICC	4082.12193
MAPE	4.63908859	HQC	4102.52974
Log Likelihood	-2023.9035	Transformed Regression R-Square	0.7975
Durbin-Watson	1.8926	Total R-Square	0.8999
		Observations	252

GNT BACKBONE-LEVEL DEMAND EQUATION

Backbone level industrial (GNTBB) usages are forecast using a model which employs recorded data from 2005 through 2023. Monthly usages are modeled as a function of real GNTBB gas rate and commodity costs, GNTBB customer count, monthly seasonal dummy variables, and a first order autoregressive term to correct for autocorrelation that may be present in the model errors; reducing potential bias in the econometric parameter estimates.

Table 9

Dependent Variable: GNTBB_USAGE
Method: Maximum Likelihood Estimates

Variable	Coefficient	Std. Error	t-Statistics	Prob.
Intercept	-95.7634	31.7946	-3.01	0.0029
Gas_price_GNTBB_12mo	0.6373	1.7121	0.37	0.7101
GNTBB_counts	36.3	4.4312	8.19	<.0001
January	-8.0866	11.1712	-0.72	0.4699
February	-11.1043	12.9649	-0.86	0.3927
March	-18.8882	13.5499	-1.39	0.1648
April	-24.0712	13.7629	-1.75	0.0817
May	-22.1166	13.8286	-1.6	0.1112
June	-8.6441	13.8467	-0.62	0.5331
July	242.1392	13.8219	17.52	<.0001
August	340.0744	13.7444	24.74	<.0001
September	310.793	13.5223	22.98	<.0001
October	120.8395	12.8953	9.37	<.0001
November	-18.4426	11.023	-1.67	0.0958
AR1	-0.3696	0.0639	-5.78	<.0001

SSE	337434.976	DFE	213
MSE	1584	Root MSE	39.80203
SBC	2392.97344	AIC	2341.53326
MAE	24.0978447	AICC	2343.79741
MAPE	48.4476962	HQC	2362.28781
Log Likelihood	-1155.7666	Transformed Regression R-Square	0.8911
Durbin-Watson	2.0136	Total R-Square	0.9334
		Observations	228

MONTHLY DISAGGREGATION MODELS

The aggregate monthly forecast categories are disaggregated into their component parts with spread factors.

- RESIDENTIAL:
  - RESIDENTIAL IM BUNDLE (RESIMBUN) = RESTOTAL * RESIMBUND%
  - RESIDENTIAL IM TRANSPORT (RESIMTRPT) = RESTOTAL * RESIMTRPT%
  - RESIDENTIAL MM BUNDLE (RESMMBUN) = RESTOTAL * RESMMBUND%
  - RESIDENTIAL MM TRANSPORT (RESMMTRPT) = RESTOTAL * RESMMTRPT%

- SMALL COMMERCIAL:
  - SMALL COMMERCIAL BUNDLE (SMLCOMBUN) = SMLCOMTOT * SMLCOMBUND
  - SMALL COMMERCIAL TRANSPORT (SMLCOMTRPT) = SMLCOMTOT * SMLCOTRPT%

- LARGE COMMERCIAL
  - LARGE COMMERCIAL BUNDLE (LGCOMBUN) = LGCOMTOT * LGCOMBUND%
  - LARGE COMMERCIAL TRANSPORT (LGCOMTRPT) = LGCOMTOT * LGCOTRPT%

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II.C. Forecast of Demand in the Electric Generation Market Segment

C. Forecast of Demand in the Electric Generation Market Segment

DESCRIPTION OF PLEXOS MODEL

PLEXOS is a Microsoft Windows-based software package that solves, by iteration, a system of simultaneous equations describing a market with supplies, demands, and transmission routes. PLEXOS has been widely used by the industry to model electric, water, gas, and renewable markets. Marketing information about PLEXOS is available at the vendor's web site, https://www.energyexemplar.com/products/plexos.

PG&E utilizes a Western Electricity Coordinating Council (WECC) wide PLEXOS model to forecast electric generation throughout California by optimizing power plant dispatch to meet load and operating reserve requirements while minimizing costs and following physical constraints such as along electric transmission pathways. The model is configured into regions with assigned load. Regions consist of one or more node and are connected via transmission lines. Each node contains individual generator resources. In order for the model to run, many detailed assumptions that inform system behavior and economics are required. For this model, PG&E started with Energy Exemplar's 2023 WECC Zonal Dataset. Since receiving the dataset in 2023, PG&E has reviewed assumptions and made updates utilizing more relevant information where necessary (e.g., updating to the most current gas commodity prices, aligning with current resource portfolio within CAISO, and incorporating elements from the CPUC's 2023 Preferred System Plan (2023 PSP)).

The remaining sections in this workpaper provide details on key assumptions made within various model components, as well as a discussion on uncertainty analysis on the largest drivers of Electric Generation (EG) gas demand.

TIME PERIODS IN MODELING

PLEXOS simulates the electric market on an hourly level, optimizing generation dispatch to meet load and ancillary service requirements in each hour of the forecast horizon. This results in 8,760 hours of simulation in non-leap years and 8,784 hours in leap years (e.g., 2024 and 2028). Although the model runs on an hourly time scale, many inputs are specified in less granular time steps. PLEXOS fills in hourly-level gaps as described in the examples below:

Hourly (e.g., electric load): Electric load is input at the hourly level for each hour of the forecast period. Since this is the time scale at which the model runs, PLEXObuS makes no transformation to the data. For the 2024-2040 period, one electric load input would consist of a total of 149,040 data points.

Daily (e.g., scheduled maintenance): Units may be assumed offline for a number of days in PLEXOS. An illustrative example would be a nuclear plant that goes offline for scheduled maintenance on April 1, 2022 and returns to operation 45 days later on May 16, 2022. In this case, the unit would be assumed unavailable to dispatch for every hour starting 4/1/2022 at 12 am through 5/15/2022 at 11 pm and would then return to service on 4/16/2022 at midnight.

Monthly (e.g., gas prices): Gas prices are input on a monthly level which the model then applies to each hour. As an illustrative example, if a gas price of $2.00/Dth was applied on January 1st and a value of $3.00/Dth was applied on February 1st, the model would simulate prices of $2.00/Dth for every hour in January and $3.00/Dth for every hour thereafter.

Annual or Greater (e.g., Unit Additions and Retirements): Some inputs, once specified, are used throughout the forecast horizon. These are typically specified at one point in time and then applied for every hour after. One illustrative example would be the addition of a new solar resource on January 1, 2022. This unit would be turned “on” starting 1/1/2022 at 12 am and assumed on through December 31, 2026, at 11:59 pm unless otherwise specified to retire. Another illustrative example of a unit retirement would be a gas plant retiring on 12/31/2021 at midnight. In this case, the unit would then be off for every hour starting 1/1/2022 at 12 am and remain off through 12/31/2026 at 11:59 pm unless otherwise specified to return to operation. Another example is the treatment of ancillary services. Rather than specify reserve requirements in each hour of the forecast period, these are typically specified as a percent of relevant load. When running a simulation, PLEXOS multiplies the hourly load as specified in the “hourly” description above by the fixed percentage. This creates hourly reserve requirements as a function of load.

When relevant, the time granularity of each key assumption detailed in the remainder of this Workpaper will be specified in the relevant section.

GEOGRAPHICAL AREAS IN MODELING

In PLEXOS, the WECC was modeled as 34 regions, organized by large balancing authorities. Each of these regions contains one node with associated generators and each region is assigned an hourly electric demand. Those 34 regions are presented in Table 10.

Table 10: Geographic Regions in PLEXOS Model

REGION IN MODEL	GEOGRAPHICAL REGION/ BALANCING AUTHORITY REPRESENTED
Alberta	Alberta Electric System Operator
Avista	Avista Utilities
AZPublicService	Arizona Public Service Company
BANC	Balancing Authority of Northern California
BPA	Bonneville Power Administration
BritishColumbia	British Columbia Hydro Authority
ChelanCountyPUD	PUD No 1 of Chelan County
DouglasCountyPUD	PUD No 1 of Douglas County
ElPasoElectric	El Paso Electric, New Mexico Region
GrantCountyPUD	PUD No 1 of Grant County
IdahoPower	Idaho Power & PacifiCorp Idaho
IID	Imperial Irrigation District
LDWP	Los Angeles Department of Water & Power
N_BajaCA	Baja California
Nevada	Southern Nevada (Nevada Power)
NWMT	NorthWestern Energy
PacificorpEast	PacifiCorp East - Utah & Utah Associated Municipal Power Systems
PACWSouth	PacifiCorp West
PGAE	California ISO - Pacific Gas & Electric Area
PortlandGeneral	Portland General Electric
PublicServiceCO	Public Service Company of Colorado
PublicServiceNM	Public Service Company of New Mexico
PugetSound	Puget Sound Energy
SaltRiverProject	Salt River Project
SCE	California ISO - Southern California Edison Area
SDGE	California ISO - San Diego Gas & Electric Area
SeattleCL	Seattle City Light
TacomaPower	Tacoma Power
TIDC	Turlock Irrigation District Control Area
TucsonElectric	Tucson Electric Power Company
VEA	Valley Electric Association
WAPA_CO	Western Area Power Administration, Colorado Region
WAPA_LwrCO	Western Area Power Administration, Lower Colorado Region
WAPA_UprMO	Western Area Power Administration, Upper Great Plains Region

ELECTRIC ENERGY DEMAND

For areas within California for the 2024 to 2040 forecast period, PG&E used data from the CEC's 2023 Integrated Energy Policy Report (IEPR)[1]. For each PLEXOS region within the CAISO (the three Transmission Access Charge (TAC) Areas), PG&E used hourly managed forecasts using data published on the CEC's webpage. For the 2024 CGR, PG&E used a CEC forecast that utilized the IEPR's "Planning" demand forecast and Additional Achievable Energy Efficiency (AAEE) Scenario 3. For just the PG&E TAC, PG&E applied the internal building electrification (BE)/fuel substitution assumption developed during the 2024 Annual Load Forecast (ALF) process. For the Southern California TACs, SoCalGas elected to use the "programmatic" component of the 2023 IEPR's Additional Achievable Fuel Substitution (AAFS) 3 forecast. PG&E also used this assumption in the PLEXOS model. As BE is a large driver for uncertainty in future electric load, PG&E assessed gas demand under other BE assumptions.

For non-CAISO balancing authorities (BA), PG&E used 2022 historical load data across all years. Table 11 presents the 2022 historical total monthly load to serve by PLEXOS region for balancing areas within California. Table 12 presents managed monthly load in each CAISO region throughout the forecast period, 2024-2040.

[1] IEPR source here

Table 11: Historical 2022 Monthly Managed Load to Serve by California Region, GWh

Month-Year	PG&E	SCE	SDGE	IID	LADWP	BANC	TIDC
Jan-22	7,947	7,719	1,554	219	2,070	1,645	191
Feb-22	6,995	6,891	1,374	197	1,869	1,480	172
Mar-22	7,464	7,424	1,445	232	2,018	1,614	186
Apr-22	7,084	7,295	1,372	283	1,938	1,543	194
May-22	8,050	7,783	1,414	335	2,033	1,655	232
Jun-22	9,184	9,210	1,569	437	2,110	1,801	280
Jul-22	9,800	10,287	1,744	535	2,513	2,040	326
Aug-22	10,149	11,397	2,084	510	2,467	1,939	309
Sep-22	9,399	10,618	2,058	400	2,201	1,696	253
Oct-22	8,184	8,606	1,703	273	2,061	1,611	214
Nov-22	7,604	7,450	1,500	227	1,971	1,576	192
Dec-22	8,393	8,006	1,650	223	2,057	1,662	195

Table 12: Monthly Managed Load to Serve by CAISO Region, GWh

Month	PG&E	SCE	SDGE	Month	PG&E	SCE	SDGE
Jan-24	8,419	8,907	1,700	45,318	8,225	8,118	1,671
Feb-24	7,600	8,110	1,519	45,349	7,045	7,011	1,433
Mar-24	7,857	8,634	1,533	45,378	7,532	7,473	1,480
Apr-24	7,568	8,515	1,446	45,409	6,960	7,118	1,352
May-24	8,387	9,202	1,530	45,439	7,732	7,893	1,455
Jun-24	9,195	10,433	1,550	45,470	8,664	8,712	1,526
Jul-24	10,153	11,847	1,798	45,500	9,907	10,530	1,807
Aug-24	10,013	12,141	1,884	45,531	9,753	10,716	1,971
Sep-24	9,112	11,300	1,871	45,562	8,978	9,745	1,906
Oct-24	8,409	10,217	1,767	45,592	8,102	8,593	1,740
Nov-24	7,890	9,094	1,585	45,623	7,723	7,801	1,599
Dec-24	8,724	9,673	1,750	45,653	8,502	8,341	1,733
Jan-25	8,602	9,559	1,701	45,319	8,400	8,185	1,701
Feb-25	7,484	8,421	1,470	45,350	7,442	7,311	1,510
Mar-25	8,018	9,251	1,525	45,379	7,648	7,487	1,499
Apr-25	7,746	9,236	1,446	45,410	7,060	7,123	1,370
May-25	8,503	9,923	1,520	45,440	7,812	7,885	1,474
Jun-25	9,342	10,933	1,574	45,471	8,738	8,707	1,545
Jul-25	10,313	12,206	1,812	45,501	10,016	10,541	1,829
Aug-25	10,132	12,404	1,886	45,532	9,860	10,728	1,994
Sep-25	9,227	11,601	1,884	45,563	9,113	9,788	1,935
Oct-25	8,442	10,454	1,772	45,593	8,237	8,632	1,768
Nov-25	7,982	9,311	1,591	45,624	7,883	7,859	1,628
Dec-25	8,830	9,959	1,762	45,654	8,694	8,422	1,766
Jan-26	8,082	8,075	1,649	45,320	8,614	8,260	1,734
Feb-26	6,932	6,988	1,415	45,351	7,364	7,111	1,487
Mar-26	7,442	7,488	1,467	45,380	7,805	7,518	1,524
Apr-26	6,890	7,141	1,341	45,411	7,187	7,137	1,393
May-26	7,672	7,918	1,442	45,441	7,932	7,905	1,499
Jun-26	8,597	8,736	1,515	45,472	8,853	8,725	1,569
Jul-26	9,836	10,555	1,795	45,502	10,144	10,574	1,857
Aug-26	9,680	10,736	1,956	45,533	10,006	10,765	2,024
Sep-26	8,881	9,745	1,889	45,564	9,279	9,850	1,968
Oct-26	7,991	8,576	1,721	45,594	8,402	8,687	1,799
Nov-26	7,593	7,767	1,578	45,625	8,082	7,932	1,662
Dec-26	8,350	8,289	1,709	45,655	8,925	8,513	1,803

Month	PG&E	SCE	SDGE	Month	PG&E	SCE	SDGE
Jan-30	8,869	8,341	1,769	Jan-33	9,884	8,696	1,902
Feb-30	7,579	7,172	1,519	Feb-33	8,444	7,463	1,639
Mar-30	7,996	7,553	1,551	Mar-33	8,781	7,766	1,659
Apr-30	7,345	7,152	1,417	Apr-33	8,062	7,350	1,523
May-30	8,085	7,924	1,525	May-33	8,770	8,134	1,639
Jun-30	8,998	8,747	1,595	Jun-33	9,708	8,969	1,710
Jul-30	10,309	10,601	1,887	Jul-33	11,083	10,858	2,012
Aug-30	10,196	10,810	2,058	Aug-33	11,006	11,095	2,194
Sep-30	9,478	9,908	2,004	Sep-33	10,323	10,249	2,149
Oct-30	8,617	8,759	1,835	Oct-33	9,492	9,116	1,976
Nov-30	8,324	8,015	1,698	Nov-33	9,282	8,398	1,839
Dec-30	9,200	8,607	1,843	Dec-33	10,314	9,032	1,992
Jan-31	9,160	8,438	1,810	Jan-34	10,350	8,865	1,956
Feb-31	7,822	7,248	1,555	Feb-34	8,864	7,622	1,690
Mar-31	8,212	7,601	1,583	Mar-34	9,189	7,912	1,708
Apr-31	7,534	7,191	1,448	Apr-34	8,457	7,498	1,573
May-31	8,265	7,968	1,558	May-34	9,158	8,281	1,690
Jun-31	9,179	8,790	1,628	Jun-34	10,114	9,117	1,762
Jul-31	10,501	10,646	1,922	Jul-34	11,524	11,025	2,070
Aug-31	10,411	10,876	2,098	Aug-34	11,450	11,266	2,253
Sep-31	9,710	9,991	2,046	Sep-34	10,758	10,431	2,209
Oct-31	8,861	8,850	1,878	Oct-34	9,913	9,291	2,034
Nov-31	8,603	8,123	1,742	Nov-34	9,722	8,575	1,896
Dec-31	9,519	8,725	1,888	Dec-34	10,818	9,221	2,052
Jan-32	9,514	8,553	1,853	Jan-35	10,722	9,020	2,006
Feb-32	8,375	7,570	1,643	Feb-35	9,202	7,771	1,739
Mar-32	8,485	7,662	1,617	Mar-35	9,515	8,057	1,756
Apr-32	7,782	7,246	1,481	Apr-35	8,768	7,641	1,621
May-32	8,508	8,031	1,594	May-35	9,466	8,435	1,740
Jun-32	9,420	8,848	1,663	Jun-35	10,434	9,284	1,813
Jul-32	10,776	10,718	1,960	Jul-35	11,865	11,201	2,125
Aug-32	10,691	10,951	2,140	Aug-35	11,793	11,449	2,309
Sep-32	9,995	10,087	2,092	Sep-35	11,116	10,635	2,271
Oct-32	9,156	8,951	1,921	Oct-35	10,258	9,478	2,091
Nov-32	8,920	8,228	1,785	Nov-35	10,089	8,762	1,951
Dec-32	9,895	8,849	1,935	Dec-35	11,238	9,417	2,109

Month	PG&E	SCE	SDGE	Month	PG&E	SCE	SDGE
Jan-36	11,109	9,205	2,065	Jan-39	12,144	9,679	2,204
Feb-36	9,907	8,245	1,861	Feb-39	10,492	8,404	1,930
Mar-36	9,863	8,240	1,814	Mar-39	10,748	8,678	1,945
Apr-36	9,098	7,820	1,678	Apr-39	9,956	8,272	1,811
May-36	9,799	8,628	1,800	May-39	10,644	9,103	1,939
Jun-36	10,776	9,480	1,874	Jun-39	11,613	9,955	2,013
Jul-36	12,216	11,404	2,189	Jul-39	13,115	11,916	2,339
Aug-36	12,158	11,662	2,377	Aug-39	13,051	12,174	2,529
Sep-36	11,458	10,833	2,335	Sep-39	12,352	11,360	2,492
Oct-36	10,604	9,680	2,155	Oct-39	11,505	10,191	2,305
Nov-36	10,462	8,964	2,014	Nov-39	11,405	9,443	2,156
Dec-36	11,646	9,609	2,171	Dec-39	12,754	10,102	2,317
Jan-37	11,475	9,379	2,116	Jan-40	12,454	9,804	2,242
Feb-37	9,889	8,117	1,845	Feb-40	11,170	8,845	2,040
Mar-37	10,178	8,399	1,862	Mar-40	11,013	8,801	1,982
Apr-37	9,403	7,983	1,727	Apr-40	10,215	8,397	1,849
May-37	10,107	8,806	1,851	May-40	10,883	9,224	1,976
Jun-37	11,067	9,647	1,924	Jun-40	11,862	10,082	2,051
Jul-37	12,539	11,593	2,245	Jul-40	13,379	12,059	2,381
Aug-37	12,481	11,849	2,433	Aug-40	13,324	12,324	2,574
Sep-37	11,772	11,019	2,391	Sep-40	12,627	11,515	2,537
Oct-37	10,926	9,867	2,210	Oct-40	11,758	10,324	2,346
Nov-37	10,797	9,138	2,066	Nov-40	11,688	9,578	2,196
Dec-37	12,035	9,788	2,224	Dec-40	13,093	10,242	2,358
Jan-38	11,817	9,536	2,162				
Feb-38	10,196	8,267	1,889				
Mar-38	10,468	8,543	1,905				
Apr-38	9,685	8,132	1,771				
May-38	10,383	8,962	1,897				
Jun-38	11,348	9,810	1,971				
Jul-38	12,833	11,760	2,293				
Aug-38	12,773	12,020	2,484				
Sep-38	12,070	11,197	2,444				
Oct-38	11,225	10,039	2,260				
Nov-38	11,106	9,296	2,113				
Dec-38	12,399	9,952	2,273				

To create the cold-year forecast, PG&E scaled load for the PG&E region by a monthly factor based on an increase in heating degree days relative to an average year. Table 13 summarizes monthly factors for the 2024 through 2040 forecast period.

Table 13: Cold-Year 1-in-10 Scaling Factor for PG&E Region Load

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2024	1.023	1.019	1.025	1.023	1.030	1.030	1.028	1.022	1.016	1.016	1.018	1.018
2025	1.023	1.020	1.025	1.024	1.030	1.031	1.028	1.023	1.017	1.017	1.018	1.019
2026	1.024	1.020	1.025	1.024	1.030	1.031	1.029	1.023	1.017	1.017	1.019	1.019
2027	1.024	1.020	1.024	1.024	1.030	1.032	1.029	1.023	1.017	1.017	1.019	1.020
2028	1.024	1.021	1.024	1.024	1.030	1.032	1.029	1.024	1.018	1.017	1.019	1.020
2029	1.025	1.021	1.024	1.024	1.031	1.032	1.030	1.024	1.018	1.017	1.019	1.021
2030	1.025	1.021	1.023	1.024	1.030	1.033	1.030	1.024	1.018	1.017	1.019	1.021
2031	1.025	1.021	1.023	1.024	1.030	1.032	1.030	1.024	1.018	1.017	1.019	1.022
2032	1.025	1.021	1.023	1.023	1.030	1.032	1.030	1.024	1.017	1.017	1.019	1.022
2033	1.026	1.022	1.022	1.023	1.029	1.032	1.029	1.024	1.017	1.017	1.019	1.023
2034	1.026	1.022	1.022	1.023	1.029	1.032	1.029	1.023	1.017	1.016	1.019	1.023
2035	1.026	1.022	1.021	1.023	1.028	1.031	1.029	1.023	1.017	1.016	1.019	1.024
2036	1.026	1.022	1.021	1.022	1.028	1.031	1.028	1.023	1.016	1.016	1.019	1.024
2037	1.026	1.022	1.020	1.022	1.027	1.030	1.028	1.022	1.016	1.016	1.019	1.024
2038	1.026	1.022	1.020	1.022	1.026	1.030	1.027	1.022	1.016	1.016	1.019	1.025
2039	1.026	1.022	1.019	1.021	1.026	1.029	1.027	1.022	1.016	1.015	1.019	1.025
2040	1.027	1.022	1.019	1.021	1.025	1.029	1.027	1.021	1.015	1.015	1.019	1.026

For WECC regions outside California for all years, hourly demand was held at historical 2022 levels. Table 14 presents total monthly demand for the 27 modeled regions outside California.

Table 14: Historical 2022 Monthly Managed Load by WECC Region, GWh

Region	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	7,918	7,267	7,430	6,676	6,833	6,884	7,336	7,117	6,699	7,277	7,427	7,946
Avista	898	871	814	699	724	760	862	800	690	761	818	914
AZ Public Service	2,192	1,947	2,037	2,169	2,566	3,262	3,815	3,661	2,999	2,236	2,060	2,285
BPA	322	313	293	258	265	267	286	271	244	271	294	331
British Columbia	6,608	6,277	5,912	4,931	4,838	4,807	5,086	5,015	4,724	5,480	5,950	6,694
Chelan County PUD	220	209	163	117	112	122	140	132	116	142	181	229
Douglas County PUD	194	185	160	135	147	158	176	165	143	157	177	208
ElPaso Electric	635	538	582	620	799	962	1,028	1,028	839	642	580	630
Grant County PUD	472	440	433	436	498	534	574	533	453	460	457	483
Idaho Power	158	141	120	119	175	239	251	200	143	129	145	177
BajaCA	1,042	960	1,074	1,139	1,314	1,581	1,867	1,895	1,581	1,213	1,078	1,042
Nevada	708	634	670	691	810	1,018	1,203	1,130	879	696	673	743
NWMT	1,102	1,060	998	890	913	966	1,116	1,019	922	976	1,026	1,101
Pacificorp East	280	243	251	256	324	429	448	357	277	241	256	300
PACW South	2,009	1,921	1,782	1,494	1,556	1,703	1,998	1,875	1,534	1,630	1,824	2,057
Portland General	1,873	1,739	1,789	1,640	1,673	1,681	1,871	1,842	1,642	1,735	1,767	1,912
Public Service CO	4,089	3,706	3,866	3,622	3,866	4,192	4,720	4,572	3,967	3,898	3,943	4,203
Public Service NM	1,170	1,022	1,033	967	1,103	1,277	1,398	1,353	1,164	1,059	1,095	1,227
Puget Sound	1,979	1,936	1,769	1,424	1,332	1,353	1,479	1,448	1,330	1,596	1,785	2,049
Salt River Project	1,980	1,768	1,861	2,135	2,583	3,308	3,863	3,669	2,968	2,114	1,833	2,054
SeattleCL	847	802	796	720	711	696	729	722	689	761	784	854
Tacoma Power	494	477	450	376	351	341	364	360	340	402	444	505
Tucson Electric	1,212	1,079	1,140	1,152	1,317	1,575	1,704	1,653	1,419	1,186	1,118	1,232
VEA	42	38	38	41	52	70	85	79	58	41	40	46
WAPA CO	1,338	1,227	1,249	1,148	1,141	1,202	1,363	1,295	1,141	1,159	1,175	1,261
WAPA LwrCO	558	597	665	764	856	900	943	899	855	703	596	581
WAPA UprMO	76	77	64	48	50	71	94	70	49	49	55	67

Local Area Generation Requirements

For each region defined within California, modeling constraints were applied to certain local areas and regions in the PLEXOS model using internally developed assumptions[2]. Table 15 summarizes the local requirements for these regions across modeled years 2024-2030, then are scaled down linearly 10% each year until reaching 0 GWh in 2040. PG&E summarized monthly electric generation from natural gas generators in each CAISO local area[3] for the years of 2018 through 2022[4] and then selected the monthly minimum value to represent the minimum requirement to input into PLEXOS.

Table 15: CAISO Monthly Local Minimum Generation Requirements, GWh

Month	Bay Area	BC Ventura	Fresno	Humboldt	LA Basin	SD-IV	Sierra	Stockton
Jan	1,361	410	1	22	99	92	27	17
Feb	954	105	1	20	129	151	0	0
Mar	910	123	5	24	170	94	0	16
Apr	504	61	1	28	253	141	0	0
May	420	63	4	24	150	94	0	6
Jun	787	256	7	25	233	134	15	25
Jul	1,618	435	10	22	595	155	51	46
Aug	1,910	417	14	39	452	268	100	76
Sep	1,663	374	10	29	354	260	74	39
Oct	1,752	366	7	33	395	290	88	38
Nov	1,496	168	7	28	332	249	62	0
Dec	1,888	427	2	33	59	72	115	12

Natural Gas Price Forecast

The 2024 CGR gas price forecast was developed using S&P Global gas commodity price forecasts.[5]

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[2] Four of these were present in the dataset provided to PG&E by the CEC, requiring some fraction of the demand in these regions to be served by specific generators within each local area.

[3] PG&E identified relevant thermal generators for each "LCR Area Name" in the CAISO's List of Physical Resources dataset: https://www.caiso.com/InitiativeDocuments/Attachment-A-List-of-Physical-Resources-Accounted-for-in-the-2024-and-2028-Local-Capacity-Technical-Studies.xls

[4] Monthly plant-level generation data can be found on the EIA's website here: https://www.eia.gov/electricity/data/eia923/

[5] North American Natural Gas Long-Term Outlook. S&P Global Commodity Insights, February 2024

For non-California NG plants, estimates of gas transmission and distribution (transportation) charges were added to the commodity prices to produce the monthly “burnertip” gas prices used in PLEXOS. For within California NG plants, PG&E used internally set transportation rates (confidential).

For California Plants: burnertip prices in Table 16.

For Non-California Plants: burnertip prices in Table 17.

Table 16: Monthly Burnertip Gas Prices for California Plants, $/Dth

Month-Year	NG Blythe	NG Kern River	NG Malin	NG Mojave PL	NG Otay Mesa	NG PG&E BB	NG PG&E LT	NG Rosarito CA	NG S Cal Prod	NG SCG	NG SDG&E	NG TEOR Cogen
Jan-24	[redacted]											
Feb-24	[redacted]											
Mar-24	[redacted]											
Apr-24	[redacted]											
May-24	[redacted]											
Jun-24	[redacted]											
Jul-24	[redacted]											
Aug-24	[redacted]											
Sep-24	[redacted]											
Oct-24	[redacted]											
Nov-24	[redacted]											
Dec-24	[redacted]											
Jan-25	[redacted]											
Feb-25	[redacted]											
Mar-25	[redacted]											
Apr-25	[redacted]											
May-25	[redacted]											
Jun-25	[redacted]											
Jul-25	[redacted]											
Aug-25	[redacted]											
Sep-25	[redacted]											
Oct-25	[redacted]											
Nov-25	[redacted]											
Dec-25	[redacted]											
Jan-26	[redacted]											
Feb-26	[redacted]											
Mar-26	[redacted]											
Apr-26	[redacted]											
May-26	[redacted]											
Jun-26	[redacted]											
Jul-26	[redacted]											
Aug-26	[redacted]											
Sep-26	[redacted]											
Oct-26	[redacted]											
Nov-26	[redacted]											
Dec-26	[redacted]											
Jan-27	[redacted]											
Feb-27	[redacted]											
Mar-27	[redacted]											
Apr-27	[redacted]											
May-27	[redacted]											
Jun-27	[redacted]											
Jul-27	[redacted]											
Aug-27	[redacted]											
Sep-27	[redacted]											
Oct-27	[redacted]											
Nov-27	[redacted]											
Dec-27	[redacted]											
Jan-28	[redacted]											
Feb-28	[redacted]											
Mar-28	[redacted]											
Apr-28	[redacted]											
May-28	[redacted]											
Jun-28	[redacted]											
Jul-28	[redacted]											
Aug-28	[redacted]											
Sep-28	[redacted]											
Oct-28	[redacted]											
Nov-28	[redacted]											
Dec-28	[redacted]											

Table 16: Monthly Burnertip Gas Prices for California Plants, $/Dth (continued)

Month-Year	NG Blythe	NG Kern River	NG Malin	NG Mojave PL	NG Otay Mesa	NG PG&E BB	NG PG&E LT	NG Rosarito CA	NG S Cal Prod	NG SCG	NG SDG&E	NG TEOR Cogen
Jan-29	[redacted]											
Feb-29	[redacted]											
Mar-29	[redacted]											
Apr-29	[redacted]											
May-29	[redacted]											
Jun-29	[redacted]											
Jul-29	[redacted]											
Aug-29	[redacted]											
Sep-29	[redacted]											
Oct-29	[redacted]											
Nov-29	[redacted]											
Dec-29	[redacted]											
Jan-30	[redacted]											
Feb-30	[redacted]											
Mar-30	[redacted]											
Apr-30	[redacted]											
May-30	[redacted]											
Jun-30	[redacted]											
Jul-30	[redacted]											
Aug-30	[redacted]											
Sep-30	[redacted]											
Oct-30	[redacted]											
Nov-30	[redacted]											
Dec-30	[redacted]											
Jan-31	[redacted]											
Feb-31	[redacted]											
Mar-31	[redacted]											
Apr-31	[redacted]											
May-31	[redacted]											
Jun-31	[redacted]											
Jul-31	[redacted]											
Aug-31	[redacted]											
Sep-31	[redacted]											
Oct-31	[redacted]											
Nov-31	[redacted]											
Dec-31	[redacted]											
Jan-32	[redacted]											
Feb-32	[redacted]											
Mar-32	[redacted]											
Apr-32	[redacted]											
May-32	[redacted]											
Jun-32	[redacted]											
Jul-32	[redacted]											
Aug-32	[redacted]											
Sep-32	[redacted]											
Oct-32	[redacted]											
Nov-32	[redacted]											
Dec-32	[redacted]											
Jan-33	[redacted]											
Feb-33	[redacted]											
Mar-33	[redacted]											
Apr-33	[redacted]											
May-33	[redacted]											
Jun-33	[redacted]											
Jul-33	[redacted]											
Aug-33	[redacted]											
Sep-33	[redacted]											
Oct-33	[redacted]											
Nov-33	[redacted]											
Dec-33	[redacted]											

Table 16: Monthly Burnertip Gas Prices for California Plants, $/Dth (continued)

Month-Year	NG Blythe	NG Kern River	NG Malin	NG Mojave PL	NG Otay Mesa	NG PG&E BB	NG PG&E LT	NG Rosarito CA	NG S Cal Prod	NG SCG	NG SDG&E	NG TEOR Cogen
Jan-34	[redacted]											
Feb-34												
Mar-34												
Apr-34												
May-34												
Jun-34												
Jul-34												
Aug-34												
Sep-34												
Oct-34												
Nov-34												
Dec-34												
Jan-35	[redacted]											
Feb-35												
Mar-35												
Apr-35												
May-35												
Jun-35												
Jul-35												
Aug-35												
Sep-35												
Oct-35												
Nov-35												
Dec-35												
Jan-36	[redacted]											
Feb-36												
Mar-36												
Apr-36												
May-36												
Jun-36												
Jul-36												
Aug-36												
Sep-36												
Oct-36												
Nov-36												
Dec-36												
Jan-37	[redacted]											
Feb-37												
Mar-37												
Apr-37												
May-37												
Jun-37												
Jul-37												
Aug-37												
Sep-37												
Oct-37												
Nov-37												
Dec-37												
Jan-38												
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Sep-38												
Oct-38												
Nov-38												
Dec-38												

Table 16: Monthly Burnertip Gas Prices for California Plants, $/Dth (continued)

Month-Year	NG Blythe	NG Kern River	NG Malin	NG Mojave PL	NG Otay Mesa	NG PG&E BB	NG PG&E LT	NG Rosarito CA	NG S Cal Prod	NG SCG	NG SDG&E	NG TEOR Cogen
Jan-39	[redacted]											
Feb-39												
Mar-39												
Apr-39												
May-39												
Jun-39												
Jul-39												
Aug-39												
Sep-39												
Oct-39												
Nov-39												
Dec-39												
Jan-40	[redacted]											
Feb-40												
Mar-40												
Apr-40												
May-40												
Jun-40												
Jul-40												
Aug-40												
Sep-40												
Oct-40												
Nov-40												
Dec-40												

Table 17: Monthly Burnertip Gas Prices for Non-California Plants, $/Dth

Month-Year	NG Alberta	NG BC	NG Colorado	NG Idaho	NG Kingsgate ID	NG Montana	NG N Nevada	NG No AZ	NG No NM	NG Oregon	NG Rosarito CFE	NG S Nevada	NG So AZ	NG So AZ CA	NG So NM	NG Utah	NG Washington	NG West Texas	NG Wyoming
Jan-24	[redacted]																		
Feb-24	[redacted]																		
Mar-24	[redacted]																		
Apr-24	[redacted]																		
May-24	[redacted]																		
Jun-24	[redacted]																		
Jul-24	[redacted]																		
Aug-24	[redacted]																		
Sep-24	[redacted]																		
Oct-24	[redacted]																		
Nov-24	[redacted]																		
Dec-24	[redacted]																		
Jan-25	[redacted]																		
Feb-25	[redacted]																		
Mar-25	[redacted]																		
Apr-25	[redacted]																		
May-25	[redacted]																		
Jun-25	[redacted]																		
Jul-25	[redacted]																		
Aug-25	[redacted]																		
Sep-25	[redacted]																		
Oct-25	[redacted]																		
Nov-25	[redacted]																		
Dec-25	[redacted]																		
Jan-26	[redacted]																		
Feb-26	[redacted]																		
Mar-26	[redacted]																		
Apr-26	[redacted]																		
May-26	[redacted]																		
Jun-26	[redacted]																		
Jul-26	[redacted]																		
Aug-26	[redacted]																		
Sep-26	[redacted]																		
Oct-26	[redacted]																		
Nov-26	[redacted]																		
Dec-26	[redacted]																		
Jan-27	[redacted]																		
Feb-27	[redacted]																		
Mar-27	[redacted]																		
Apr-27	[redacted]																		
May-27	[redacted]																		
Jun-27	[redacted]																		
Jul-27	[redacted]																		
Aug-27	[redacted]																		
Sep-27	[redacted]																		
Oct-27	[redacted]																		
Nov-27	[redacted]																		
Dec-27	[redacted]																		

Table 17: Monthly Burnertip Gas Prices for Non-California Plants, $/Dth (continued)

Month-Year	NG Alberta	NG BC	NG Colorado	NG Idaho	NG Kingsgate ID	NG Montana	NG N Nevada	NG No AZ	NG No NM	NG Oregon	NG Rosarito CFE	NG S Nevada	NG So AZ	NG So AZ CA	NG So NM	NG Utah	NG Washington	NG West Texas	NG Wyoming
Jan-28	[redacted]																		
Feb-28	[redacted]																		
Mar-28	[redacted]																		
Apr-28	[redacted]																		
May-28	[redacted]																		
Jun-28	[redacted]																		
Jul-28	[redacted]																		
Aug-28	[redacted]																		
Sep-28	[redacted]																		
Oct-28	[redacted]																		
Nov-28	[redacted]																		
Dec-28	[redacted]																		
Jan-29	[redacted]																		
Feb-29	[redacted]																		
Mar-29	[redacted]																		
Apr-29	[redacted]																		
May-29	[redacted]																		
Jun-29	[redacted]																		
Jul-29	[redacted]																		
Aug-29	[redacted]																		
Sep-29	[redacted]																		
Oct-29	[redacted]																		
Nov-29	[redacted]																		
Dec-29	[redacted]																		
Jan-30	[redacted]																		
Feb-30	[redacted]																		
Mar-30	[redacted]																		
Apr-30	[redacted]																		
May-30	[redacted]																		
Jun-30	[redacted]																		
Jul-30	[redacted]																		
Aug-30	[redacted]																		
Sep-30	[redacted]																		
Oct-30	[redacted]																		
Nov-30	[redacted]																		
Dec-30	[redacted]																		
Jan-31	[redacted]																		
Feb-31	[redacted]																		
Mar-31	[redacted]																		
Apr-31	[redacted]																		
May-31	[redacted]																		
Jun-31	[redacted]																		
Jul-31	[redacted]																		
Aug-31	[redacted]																		
Sep-31	[redacted]																		
Oct-31	[redacted]																		
Nov-31	[redacted]																		
Dec-31	[redacted]																		

Table 17: Monthly Burnertip Gas Prices for Non-California Plants, $/Dth (continued)

Month-Year	NG Alberta	NG BC	NG Colorado	NG Idaho	NG Kingsgate ID	NG Montana	NG N Nevada	NG No AZ	NG No NM	NG Oregon	NG Rosarito CFE	NG S Nevada	NG So AZ	NG So AZ CA	NG So NM	NG Utah	NG Washington	NG West Texas	NG Wyoming
Jan-32	[redacted]																		
Feb-32	[redacted]																		
Mar-32	[redacted]																		
Apr-32	[redacted]																		
May-32	[redacted]																		
Jun-32	[redacted]																		
Jul-32	[redacted]																		
Aug-32	[redacted]																		
Sep-32	[redacted]																		
Oct-32	[redacted]																		
Nov-32	[redacted]																		
Dec-32	[redacted]																		
Jan-33	[redacted]																		
Feb-33	[redacted]																		
Mar-33	[redacted]																		
Apr-33	[redacted]																		
May-33	[redacted]																		
Jun-33	[redacted]																		
Jul-33	[redacted]																		
Aug-33	[redacted]																		
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Oct-33	[redacted]																		
Nov-33	[redacted]																		
Dec-33	[redacted]																		
Jan-34	[redacted]																		
Feb-34	[redacted]																		
Mar-34	[redacted]																		
Apr-34	[redacted]																		
May-34	[redacted]																		
Jun-34	[redacted]																		
Jul-34	[redacted]																		
Aug-34	[redacted]																		
Sep-34	[redacted]																		
Oct-34	[redacted]																		
Nov-34	[redacted]																		
Dec-34	[redacted]																		
Jan-35	[redacted]																		
Feb-35	[redacted]																		
Mar-35	[redacted]																		
Apr-35	[redacted]																		
May-35	[redacted]																		
Jun-35	[redacted]																		
Jul-35	[redacted]																		
Aug-35	[redacted]																		
Sep-35	[redacted]																		
Oct-35	[redacted]																		
Nov-35	[redacted]																		
Dec-35	[redacted]																		

Table 17: Monthly Burnertip Gas Prices for Non-California Plants, $/Dth (continued)

Month-Year	NG Alberta	NG BC	NG Colorado	NG Idaho	NG Kingsgate ID	NG Montana	NG N Nevada	NG No AZ	NG No NM	NG Oregon	NG Rosarito CFE	NG S Nevada	NG So AZ	NG So AZ CA	NG So NM	NG Utah	NG Washington	NG West Texas	NG Wyoming
Jan-36	[redacted]																		
Feb-36																			
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Dec-40																			

GREENHOUSE GAS ALLOWANCE PRICES

Greenhouse gas (GHG) allowance prices in California for 2024–2040 are from the CEC's 2023 IEPR mid-case forecast[6]. These are input into PLEXOS at the monthly level and applied to all generators powered by a carbon-emitting fuel in the state. CEC IEPR prices are provided in dollars per metric ton ($/MT) but since PLEXOS requires input in dollars per pound ($/lb.), to convert, PG&E multiplied CEC prices by 2,204.6 lb./MT before entering into PLEXOS.[7] Monthly GHG allowance prices for California are presented in Table 18 below.

Table 18: California Greenhouse Gas Allowance Price by Month, $/lb.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2024	0.0182	0.0188	0.0184	0.0198	0.0198	0.0198	0.0198	0.0198	0.0198	0.0198	0.0198	0.0198
2025	0.0230	0.0230	0.0230	0.0230	0.0230	0.0230	0.0230	0.0230	0.0230	0.0230	0.0230	0.0230
2026	0.0269	0.0269	0.0269	0.0269	0.0269	0.0269	0.0269	0.0269	0.0269	0.0269	0.0269	0.0269
2027	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313
2028	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365	0.0365
2029	0.0425	0.0425	0.0425	0.0425	0.0425	0.0425	0.0425	0.0425	0.0425	0.0425	0.0425	0.0425
2030	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495	0.0495
2031	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531	0.0531
2032	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568	0.0568
2033	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609	0.0609
2034	0.0652	0.0652	0.0652	0.0652	0.0652	0.0652	0.0652	0.0652	0.0652	0.0652	0.0652	0.0652
2035	0.0699	0.0699	0.0699	0.0699	0.0699	0.0699	0.0699	0.0699	0.0699	0.0699	0.0699	0.0699
2036	0.0750	0.0750	0.0750	0.0750	0.0750	0.0750	0.0750	0.0750	0.0750	0.0750	0.0750	0.0750
2037	0.0805	0.0805	0.0805	0.0805	0.0805	0.0805	0.0805	0.0805	0.0805	0.0805	0.0805	0.0805
2038	0.0864	0.0864	0.0864	0.0864	0.0864	0.0864	0.0864	0.0864	0.0864	0.0864	0.0864	0.0864
2039	0.0928	0.0928	0.0928	0.0928	0.0928	0.0928	0.0928	0.0928	0.0928	0.0928	0.0928	0.0928
2040	0.0997	0.0997	0.0997	0.0997	0.0997	0.0997	0.0997	0.0997	0.0997	0.0997	0.0997	0.0997

6 https://efiling.energy.ca.gov/GetDocument.aspx?tn=254569&DocumentContentId=89994

7 There are 1,000 kg per metric ton and 2.2046 lb. per kg resulting. Multiplying these together yields 2,204.6 lb./MT. https://www.eia.gov/state/seds/sep_use/notes/use_e.pdf

ELECTRIC TRANSMISSION

Electric transmission paths in PLEXOS connect specific nodes and allow electricity to flow between regions in the WECC. Capacity on each line is constrained in both the direction of flow (node A to node B) and flow back (node B to node A). Table 19 presents details on in-state transmission lines between California regions and Table 20 presents details on the lines connecting California to its surrounding states, allowing for the import or export of electricity. The lines formatted in *italics* are dedicated import lines connecting a contracted resource out-of-state to CAISO.

Table 19: California Intrastate Lines and Summer Capacity, MW

Line	Node A	Node B	Capacity A to B	Capacity B to A
BANC-TID	BANC	TID	492	640
BANC-PGAE	BANC	PGAE	1,011	2,333
IID-SCE (42;46)	IID	SCE	600	600
IID-SDGE	IV-NG	SDGE	150	150
LADWP-SCE (41;60;61)	LDWP	SCE	4,000	3,750
PGAE-TID	PG&E	TID	683	407
PGAE-SCE (Path 26)	PG&E	SCE	4,000	3,000
SDGE-SCE	SDGE	SCE	2,500	4,800

Table 20: California Import/Export Lines and Summer Capacity, MW

Line	Node A	Node B	Capacity A to B	Capacity B to A
AZPublicService-to-LDWP	AZPS	LDWP	1,603	116
AZPublicService-to-SCE	AZPS	SCE	2,102	468
BPA-to-BANC	BPA	BANC	2,333	1,011
BPA-to-LDWP	BPA	LDWP	3,198	993
BPA-to-PGAE	BPA	PGAE	3,325	1,838
IID-to-AZPublicService	IID	AZPS	626	439
IID-to-WAPA_LwrCO	IID	WAPA LwrCo	861	118
LDWP-to-Nevada	LDWP	Nevada	1,568	556
LDWP-to-WAPA_LwrCO	LDWP	WAPA LwrCo	617	2,652
N_BajaCA-to-SDGE	Baja CA	SDGE	534	524
PacificorpEast-to-LDWP	Pacificorp East	LDWP	638	835
PACWSouth-to-PGAE	PACWSouth	PGAE	137	39
PGAE-to-Nevada	PGAE	Nevada	100	100
SaltRiverProject-to-SCE	SRP	SCE	1,308	206
SaltRiverProject-to-SDGE	SRP	SDGE	4,331	682
SCE-to-Nevada	SCE	Nevada	2,814	2,814
SDGE-to-AZPublicService	SDGE	AZPS	1,168	1,655
WAPA_LwrCO-to-SCE	WAPA LwrCO	SCE	930	291
AZPublicService-to-SCE (PaloVerde)	AZPS	SCE	650	0
AZPublicService-to-SCE (RPS)	AZPS	SCE	730	0
BPA-to-PGAE (NW Hydro)	BPA	PGAE	5,704	0
BPA-to-PGAE (RPS)	BPA	PGAE	199	0
IID-to-SCE (RPS)	IID	SCE	291	0
LDWP-to-SCE (Coal)	LDWP	SCE	480	0
SaltRiverProject-to-SCE (NG)	SRP	SCE	580	0
SaltRiverProject-to-SCE (RPS)	SRP	SCE	545	0
Nevada-to-SCE (Hoover)	Nevada	SCE	594	0
Nevada-to-SCE (RPS)	Nevada	SCE	550	0
WAPA_LwrCO-to-SCE (NG)	WAPA LwrCO	SCE	570	0

PG&E's PLEXOS model also includes constraints on *total* import and export availability across the above-described modeled lines. In order to capture recent trends in import availability into CAISO, for the 2024 CGR we limited CAISO imports to historical 2023 levels using the monthly average hourly recorded flow into CAISO. Table 21 below presents the proportion of imports vs. thermal generation meeting CAISO load over the previous 9 years. There is a clear decline in overall imported energy into CAISO, leading to additional thermal generation needed to meet demand.

Table 21: CAISO Historical Imports and Thermal Generation, GWh

Year	2015	2016	2017	2018	2019	2020	2021	2022	2023
Thermal Generation	95,859	75,325	64,907	64,372	64,698	71,684	76,514	80,589	80,881
Total Imports	63,184	64,591	61,153	61,446	51,742	56,362	50,452	44,177	23,961

Many lines include a price to transmit power between regions. Additionally, California import/export lines include GHG allowance prices when power flows into the state. To incorporate the GHG allowance prices, the CEC GHG allowance prices described above are converted from dollars per pound to dollars per kWh and are added to the price to transmit power. Table 22 below summarizes the emissions price applied to unspecified imports into California by year.

Table 22: GHG Allowance Prices for California Imports, $/MWh

Year	Coal CO_2	PNW CO_2	WECC CO_2	MEAD CO_2
2024	41.41	13.24	16.55	16.97
2025	46.44	14.85	18.56	19.02
2026	55.37	17.69	22.12	22.69
2027	63.74	20.37	25.47	26.11
2028	71.89	22.97	28.73	29.44
2029	82.90	26.50	33.13	33.97
2030	97.24	31.07	38.86	39.83
2031	105.35	33.66	42.09	43.15
2032	114.86	36.70	45.89	47.04
2033	128.80	41.16	51.46	52.75
2034	138.63	44.30	55.39	56.78
2035	153.40	49.02	61.30	62.85
2036	167.32	53.47	66.85	68.53
2037	186.79	59.70	74.64	76.52
2038	202.46	64.70	80.90	82.92
2039	224.29	71.67	89.63	91.88
2040	245.98	78.60	98.28	100.75

Finally, out-of-state transmission lines are also modeled using specifications present in the model provided by the CEC. Table 23 presents the characteristics for each out-of-state line. The model does not assume any transmission losses between out-of-state regions.

Table 23: Out-of-State Lines and Summer Capacity, MW

Line	Node A	Node B	Capacity A to B	Capacity B to A
Alberta-to-BritishColumbia	Alberta	BritishColumbia	1,000	1,200
Alberta-to-NWMT	Alberta	NWMT	287	309
Avista-to-BPA	Avista	BPA	324	1,684
Avista-to-GrantCountyPUD	Avista	GrantCountyPUD	5,968	7,316
AZPublicService-to-PublicServiceNM	AZPublicService	PublicServiceNM	876	481
AZPublicService-to-TucsonElectric	AZPublicService	TucsonElectric	1,484	817
AZPublicService-to-WAPA_LwrCO	AZPublicService	WAPA_LwrCO	2,907	395
BPA-to-BritishColumbia	BPA	BritishColumbia	2,445	2,807
BPA-to-Nevada	BPA	Nevada	276	178
BPA-to-NWMT	BPA	NWMT	957	1,854
BPA-to-PACWSouth	BPA	PACWSouth	5,075	502
BPA-to-PortlandGeneral	BPA	PortlandGeneral	3,024	255
BPA-to-PugetSound	BPA	PugetSound	3,850	32
BPA-to-TacomaPower	BPA	TacomaPower	764	235
BritishColumbia-to-Alberta	BritishColumbia	Alberta	800	800
BritishColumbia-to-Avista	BritishColumbia	Avista	15,000	15,000
BritishColumbia-to-PugetSound	BritishColumbia	PugetSound	15,000	15,000
ChelanCountyPUD-to-Avista	ChelanCountyPUD	Avista	36	67
ChelanCountyPUD-to-BPA	ChelanCountyPUD	BPA	1,710	252
DouglasCountyPUD-to-BPA	DouglasCountyPUD	BPA	6,982	509
DouglasCountyPUD-to-ChelanCountyPUD	DouglasCountyPUD	ChelanCountyPUD	2,737	367
DouglasCountyPUD-to-GrantCountyPUD	DouglasCountyPUD	GrantCountyPUD	348	348
ElPasoElectric-to-PublicServiceNM	ElPasoElectric	PublicServiceNM	223	720
ElPasoElectric-to-TucsonElectric	ElPasoElectric	TucsonElectric	511	665
GrantCountyPUD-to-BPA	GrantCountyPUD	BPA	7,293	5,641
GrantCountyPUD-to-DouglasCountyPUD	GrantCountyPUD	DouglasCountyPUD	15,000	15,000
GrantCountyPUD-to-PACWSouth	GrantCountyPUD	PACWSouth	456	124

Line	Node A	Node B	Capacity A to B	Capacity B to A
IdahoPower-to-Avista	IdahoPower	Avista	309	324
IdahoPower-to-BPA	IdahoPower	BPA	291	218
IdahoPower-to-Nevada	IdahoPower	Nevada	414	276
IdahoPower-to-PacificorpEast	IdahoPower	PacificorpEast	1,085	2,545
IdahoPower-to-PACWSouth	IdahoPower	PACWSouth	1,721	1,341
Nevada-to-PACWSouth	Nevada	PACWSouth	15,000	15,000
Nevada-to-SaltRiverProject	Nevada	SaltRiverProject	15,000	15,000
Nevada-to-WAPA_LwrCO	Nevada	WAPA_LwrCO	1,211	1,351
NWMT-to-Avista	NWMT	Avista	211	257
NWMT-to-IdahoPower	NWMT	IdahoPower	60	0
NWMT-to-PacificorpEast	NWMT	PacificorpEast	645	491
NWMT-to-WAPA_WY	NWMT	WAPA_WY	325	197
PacificorpEast-to-AZPublicService	PacificorpEast	AZPublicService	962	493
PacificorpEast-to-Nevada	PacificorpEast	Nevada	651	441
PacificorpEast-to-PublicServiceNM	PacificorpEast	PublicServiceNM	15,000	15,000
PacificorpEast-to-WAPA_LwrCO	PacificorpEast	WAPA_LwrCO	15,000	15,000
PacificorpEast-to-WAPA_WY	PacificorpEast	WAPA_WY	15,000	15,000
PACWSouth-to-Avista	PACWSouth	Avista	262	233
PACWSouth-to-Nevada	PACWSouth	Nevada	15,000	15,000
PACWSouth-to-PacificorpEast	PACWSouth	PacificorpEast	3,097	42
PACWSouth-to-PortlandGeneral	PACWSouth	PortlandGeneral	807	376
PublicServiceCO-to-PublicServiceNM	PublicServiceCO	PublicServiceNM	614	664
PublicServiceNM-to-TucsonElectric	PublicServiceNM	TucsonElectric	805	452
PugetSound-to-ChelanCountyPUD	PugetSound	ChelanCountyPUD	361	329
PugetSound-to-GrantCountyPUD	PugetSound	GrantCountyPUD	408	30
SaltRiverProject-to-AZPublicService	SaltRiverProject	AZPublicService	5,007	2,525
SaltRiverProject-to-PublicServiceNM	SaltRiverProject	PublicServiceNM	29	0
SaltRiverProject-to-TucsonElectric	SaltRiverProject	TucsonElectric	2,275	1,963
SeattleCL-to-BPA	SeattleCL	BPA	9,615	1,498

Line	Node A	Node B	Capacity A to B	Capacity B to A
SeattleCL-to-PugetSound	SeattleCL	PugetSound	289	285
TacomaPower-to-GrantCountyPUD	TacomaPower	GrantCountyPUD	15,000	15,000
TacomaPower-to-PugetSound	TacomaPower	PugetSound	117	50
VEA-to-Nevada	VEA	Nevada	800	800
VEA-to-WAPA_LwrCO	VEA	WAPA_LwrCO	120	120
WAPA_CO-to-AZPublicService	WAPA_CO	AZPublicService	1,871	667
WAPA_CO-to-PacificorpEast	WAPA_CO	PacificorpEast	1,370	717
WAPA_CO-to-PublicServiceCO	WAPA_CO	PublicServiceCO	1,135	5,257
WAPA_CO-to-PublicServiceNM	WAPA_CO	PublicServiceNM	1,902	828
WAPA_CO-to-WAPA_LwrCO	WAPA_CO	WAPA_LwrCO	766	17
WAPA_LwrCO-to-PacificorpEast	WAPA_LwrCO	PacificorpEast	15,000	15,000
WAPA_LwrCO-to-PublicServiceNM	WAPA_LwrCO	PublicServiceNM	15,000	15,000
WAPA_LwrCO-to-SaltRiverProject	WAPA_LwrCO	SaltRiverProject	15,000	15,000
WAPA_LwrCO-to-TucsonElectric	WAPA_LwrCO	TucsonElectric	424	98
WAPA_WY-to-PacificorpEast	WAPA_WY	PacificorpEast	15,000	15,000
WAPA_WY-to-WAPA_CO	WAPA_WY	WAPA_CO	219	144
WAPA_CO-to-PublicServiceNM	WAPA_CO	PublicServiceNM	1,902	828

ELECTRICITY SUPPLY

The CAISO portfolio is expected to rapidly change over the forecast period with significant additions of renewables and storage across all 3 TACs. Tables 31 and 32 summarize total installed capacity in each TAC throughout the forecast period. PG&E utilized the portfolio described in the CPUC's 2023 Preferred System Plan,[8] with modifications to near-term build in solar, wind, and storage resources to reflect recent installation rates. New installation of solar and wind resources is approximately 90% and 75% of PSP levels through 2030, respectively. Modifications to new battery storage installations are reduced through 2028 with approximately 60% of PSP levels in 2024 and aligned with the PSP by 2029.

Table 33 describes the resource portfolio in each non-CAISO region for one year, as the portfolio changes are relatively minor over the forecasting period.

PLEXOS models most generators at either the plant-level or by individual units within a plant. Installed capacities, unit start and retirement dates, startup costs, heat rates, rated capacities, etc.

The remainder of this section provides details on the unique characteristics of each resource class.

Renewable Generation

Solar and wind generation profiles and other assumptions were pre-defined by the dataset provided to PG&E, with additional calibration for in-state generators to align with historic annual generation in GWh.

Other renewable categories include geothermal, biomass, refuse, and small hydro (assumed to be hydroelectric generators with installed capacities less than or equal to 30 MW). For these categories, PG&E utilized assumptions provided in the dataset with additional calibration to align with CAISO historic annual generation.

Table 24, Table 25, and Table 26 provide annual generation results from PLEXOS for solar, wind, and other renewable resource classes respectively by region in the model. Table 27 provides renewable generation in 2024 for regions outside the CAISO.

[8] See D.21-06-035.

Table 24: CAISO Solar Generation by Region by Year, GWh

Region	2024	2025	2026	2027	2028	2029	2030	2031	2032
PGAE	13,744	14,920	14,349	14,419	14,466	15,027	15,295	15,770	15,969
SCE	27,531	30,024	34,046	38,495	42,756	48,095	53,338	57,902	61,000
SDGE	2,440	2,408	2,280	2,549	2,953	2,929	2,973	2,972	2,899

Region	2033	2034	2035	2036	2037	2038	2039	2040
PGAE	16,144	16,392	16,598	17,466	18,145	18,696	19,416	19,719
SCE	64,026	67,276	69,959	76,032	81,150	85,641	89,998	89,912
SDGE	2,701	2,686	2,688	2,706	2,656	2,553	2,701	4,615

Table 25: CAISO Wind Generation by Region by Year, GWh

Region	2024	2025	2026	2027	2028	2029	2030	2031	2032
PGAE	6,411	6,408	5,618	5,754	5,835	6,943	7,936	8,521	20,899
SCE	14,376	16,183	18,865	20,903	22,646	24,029	25,534	27,741	29,821
SDGE	1,636	1,584	1,379	1,358	1,325	1,165	1,063	1,093	1,121

Region	2033	2034	2035	2036	2037	2038	2039	2040
PGAE	23,598	26,302	29,765	30,231	30,515	30,878	31,115	31,620
SCE	30,032	33,019	39,758	41,903	43,912	45,989	47,427	47,699
SDGE	1,115	1,154	1,217	1,251	1,266	1,275	1,313	1,313

Table 26: CAISO Other Renewable Generation by Region by Year, GWh

Region	2024	2025	2026	2027	2028	2029	2030	2031	2032
PGAE	12,864	12,891	12,872	12,834	12,826	12,676	12,752	12,932	12,863
SCE	4,837	4,930	5,019	4,997	4,992	4,919	4,907	4,907	4,888
SDGE	30	31	31	30	30	29	29	1,457	2,655

Region	2033	2034	2035	2036	2037	2038	2039	2040
PGAE	12,965	13,053	13,009	13,073	13,116	13,239	13,340	13,483
SCE	4,899	4,911	4,927	4,921	4,907	4,877	4,808	4,784
SDGE	3,762	4,767	5,895	6,673	7,448	8,100	8,541	9,062

Table 27: Renewable Generation in 2024 for Non-CAISO Regions, GWh

Region	Solar	Wind	Other Renewables
Alberta	576	6,585	3,848
Avista	27	692	662
AZ Public Service	3,272	639	182
BANC	778		116
BPA	2,647	11,333	1,588
British Columbia		1,952	5,556
Chelan County PUD			
Douglas County PUD			
ElPaso Electric	353	624	415
Grant County PUD			79
Idaho Power	768	1,917	1,733
IID	846		3,826
BajaCA		1,082	4,343
LDWP	5,874	557	1,314
Nevada		1,081	4,390
NWMT	14,084	329	1,419
Pacificorp East	385	2,782	1,327
PACW South	3,732	5,826	1,589
Portland General	113	1,143	717
Public Service CO	80	1,593	173
Public Service NM	4,164	10,700	390
Puget Sound	1,630	3,898	837
Salt River Project	36	861	418
SeattleCL	969		86
Tacoma Power			604
TIDC	8		51
Tucson Electric			21
VEA	1,078	461	
WAPA CO	548	3,017	529
WAPA LwrCO	1,253	22	351
WAPA UprMO		647	39

Nuclear Power Plants

Three nuclear power plants are modeled within the WECC. Diablo Canyon Nuclear Power Plant (DCPP) within the PG&E region, Columbia Generating Station in the BPA region, and Palo Verde Nuclear Generating Station in the AZ Public Service region. The two most impactful inputs to nuclear power plant behavior are scheduled refueling and maintenance and the expected retirement of DCPP in 2029 and 2030.

Refueling of nuclear power plants tends to occur on a schedule and can last between four to six weeks. In this model, PG&E assumed that refueling is scheduled for one DCPP unit at a time, and the other unit refueling occurring six months afterwards. This is scheduled outside of high-demand summer and winter months. Tunnel cleaning tends to be scheduled in between unit refueling. These typically last less than week.

Refueling schedules for Columbia and Palo Verde are defined by setting the following parameters: forced outage rate, maintenance frequency, and mean time to repair.

Finally, DCPP is set to retire once its operating licenses tentatively expire on 11/1/2029 and 11/1/2030 for Reactor 1 and Reactor 2 respectively.

Hydroelectric Generation and Pumped Storage

In general, hydroelectric generation can be defined by three main parameters. The first is installed capacity as listed in the table at the end of this section. The second is a maximum energy per month that each generator can produce. The third, is minimum hourly flow, which only applies to a subset of generators that need to maintain a certain level of flow for non-energy reasons (e.g., recreational water use). The first and third parameter were specified once while the second varies based on whether “Average Hydroelectric” or “Dry Hydroelectric” assumptions are required.

For “Average Hydroelectric” years, the maximum energy per month is based on a 15-year average from historical CAISO generation data between 2009 and 2023.

For “Dry Hydroelectric” years, PG&E averaged historic hydroelectric generation from 2015 and 2021, the two years of lowest generation during the 15-year timeframe analyzed.

Pumped storage facilities are modeled in a different manner from traditional hydroelectric generation. In this case, each generator is assigned a “Head Storage” above the pump-generator and a “Tail Storage” below the pump-generator. Water can then generate energy by flowing from “Head” to “Tail” and consume energy by pumping from “Tail” to “Head” with energy conversion losses as water flows through the pump-generator. Behavior of these facilities does not vary between “Average Hydroelectric” and “Dry” assumptions.

Table 28 summarizes large hydroelectric generation for the “Average Demand Year” and “High Demand Year” forecast by region in PLEXOS. On average, annual hydro generation for each region is relatively constant throughout the forecast period (though simulated dispatch of hydro resources can vary widely). One year of generation data (2024) is shown for simplicity.

Table 28: Large Hydroelectric Generation by Region and Scenario by Year, GWh

Region	Average Demand	High Demand
PGAE	15,452	8,274
SCE	2,693	1,430
SDGE	0	0
IID	49	26
LDWP	654	355
BANC	2,701	1,439
TIDC	413	222
Alberta	2,060	1,829
Avista	4,485	4,262
BPA	66,191	65,221
BritishColumbia	62,135	60,237
ChelanCountyPUD	8,106	7,939
DouglasCountyPUD	4,000	3,935
GrantCountyPUD	9,442	9,238
IdahoPower	7,793	7,369
Nevada	3,488	3,288
NWMT	3,302	3,134
PacificorpEast	876	855
PACWSouth	3,574	3,394
PortlandGeneral	2,278	2,151
PugetSound	1,023	957
SaltRiverProject	256	242
SeattleCL	7,667	7,306
TacomaPower	3,128	2,852
WAPA_CO	3,619	3,410
WAPA_LwrCO	19,350	18,308
WAPA_UprMO	517	513

Thermal Power Plants

Installed capacities, unit start and retirement dates, startup costs, heat rates, and other parameters were pre-defined in the dataset provided to PG&E. Consistent with the IRP planning process, PG&E did not assume any thermal retirements in addition to those already announced. Table 29 summarizes all thermal plant retirements (including DCPP) from the State Water Resources Control Board (SWRCB) amended compliance schedule from 8/15/2023.[9]

Table 29: Once-Through Cooling Plant Retirements on or after 12/31/2023 (including DCPP)

Generating Facility by Unit	Retirement Date
Diablo Canyon Nuclear Power Plant 1	11/1/2029
Diablo Canyon Nuclear Power Plant 2	11/1/2030
Ormond Beach 1	12/31/2023
Ormond Beach 2	12/31/2023
Alamitos 3	12/31/2023
Alamitos 4	12/31/2023
Alamitos 5	12/31/2023
Haynes 1	12/31/2029
Haynes 2	12/31/2029
Haynes 8	12/31/2029
Harbor 5	12/31/2029
Huntington Beach 2	12/31/2023
Redondo Beach 5	12/31/2023
Redondo Beach 6	12/31/2023
Redondo Beach 8	12/31/2023
Scattergood 1	12/31/2029
Scattergood 2	12/31/2029

[9] Final Amendment to the Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (ca.gov)

For generators outside California, coal power plant retirements were pre-defined in the dataset provided to PG&E. Table 30 summarizes the coal retirement assumptions within the PLEXOS model.

Table 30: WECC Coal Plant Retirements Outside CAISO

Region	Generating Facility by Unit	Retirement Date
LDWP	Intermountain Power Project (1)	7/1/2025
LDWP	Intermountain Power Project (2)	7/1/2025
PublicServiceCO	Comanche (CO) (2)	12/1/2025
WAPA_CO	Craig (CO) (1)	12/1/2025
PacificorpEast	Naughton (1)	12/1/2025
PacificorpEast	Naughton (2)	12/1/2025
Nevada	North Valmy (1)	12/1/2025
Nevada	North Valmy (2)	12/1/2025
PacificorpEast	Transalta Centralia Generation	12/1/2025
Alberta	Battle River 4	1/1/2026
TusconElectric	Springerville (1)	1/1/2027
PacificorpEast	Dave Johnston (1)	12/1/2027
PacificorpEast	Dave Johnston (2)	12/1/2027
PacificorpEast	Dave Johnston (3)	12/1/2027
PacificorpEast	Dave Johnston (4)	12/1/2027
WAPA_CO	Hayden (2)	12/1/2027
Alberta	Battle River 5	1/1/2028
WAPA_CO	Craig (CO) (2)	9/1/2028
WAPA_CO	Hayden (1)	12/1/2028
Alberta	Sheerness 1	1/1/2029
Alberta	Sheerness 2	1/1/2029
WAPA_CO	Craig (CO) (3)	12/1/2029
PacificorpEast	Naughton (3)	12/1/2029
PublicServiceCO	Rawhide (1)	12/1/2029
WAPA_CO	Ray D Nixon (1)	12/1/2029
Alberta	Genesee 1	1/1/2030
Alberta	Genesee 2	1/1/2030
Alberta	Genesee 3	1/1/2030
Alberta	Keephills 3	1/1/2030
PacificorpEast	Bonanza	12/1/2030
AZPublicService	Four Corners (4)	12/1/2031

AZPublicService	Four Corners (5)	12/1/2031
SaltRiverProject	Coronado (CO1)	12/1/2032
SaltRiverProject	Coronado (CO2)	12/1/2032
PacificorpEast	Huntington (1)	12/1/2036
PacificorpEast	Huntington (2)	12/1/2036
PacificorpEast	Jim Bridger (1)	12/1/2037
PacificorpEast	Jim Bridger (2)	12/1/2037
PacificorpEast	Jim Bridger (3)	12/1/2037
PacificorpEast	Jim Bridger (4)	12/1/2037
PacificorpEast	Wyodak	12/1/2039

Battery Energy Storage

Battery energy storage (BES) installations are modeled as 4-hour or 8-hour batteries that charge, and discharge based on market pricing conditions. Batteries added to the dataset by PG&E were specified with a round-trip (charge + discharge) efficiency of 92%.

Table 31: Installed Capacity by CAISO Region by Resource Class, End of Year (MW)

Region	Year	2024	2025	2026	2027	2028	2029	2030	2031	2032
PG&E	Solar	6,351	6,361	6,422	6,461	6,488	6,547	6,607	6,649	6,690
	Wind	1,965	2,088	2,088	2,202	2,316	3,389	4,462	4,523	4,584
	Other Renewable	3,351	3,351	3,351	3,351	3,351	3,351	3,351	3,358	3,366
	Nuclear	2,240	2,240	2,240	2,240	2,240	1,118	0	0	0
	Large Hydro	5,444	5,444	5,444	5,444	5,444	5,444	5,444	5,444	5,444
	Pumped Storage	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047
	Gas	13,887	13,887	13,887	13,887	13,887	13,887	13,887	13,828	13,550
	Battery Storage	1651	3351	5442	6,396	6,777	6,935	7,092	7,406	7,719
SCE	Solar	12,240	12,748	14,686	16,479	18,201	20,105	22,015	23,897	25,784
	Wind	4,079	4,710	6,160	7,043	7,925	9,834	11,744	12,230	12,716
	Other Renewable	1,183	1,203	1,203	1,203	1,203	1,203	1,203	1,214	1,226
	Large Hydro	978	978	978	978	978	978	978	978	978
	Pumped Storage	200	200	200	200	877	877	877	877	877
	Gas	10400	10400	10400	10400	10400	10400	10400	10048	9869
	Battery Storage	5,477	6,500	6,907	7,753	8,154	9,414	10,673	10,698	10,723
SDGE	Solar	1,175	1,175	1,175	1,344	1,595	1,632	1,662	1,738	1,810
	Wind	467	467	467	467	467	467	467	467	467
	Other Renewable	6	6	6	6	6	6	6	201	395
	Pumped Storage	42	42	42	42	42	42	42	42	42
	Gas	3834	3834	3834	3834	3834	3834	3834	3806	3803
	Battery Storage	492	498	501	504	504	504	504	797	1,089

Table 32: CAISO Installed Capacity by Resource Class, End of Year (MW)

Region	Year	2033	2034	2035	2036	2037	2038	2039	2040
PG&E	Solar	6,691	6,710	6,724	6,968	7,213	7,457	7,702	7,702
	Wind	4,584	4,584	4,584	4,584	4,584	4,584	4,584	4,584
	Other Renewable	3,373	3,381	3,388	3,395	3,403	3,410	3,418	3,425
	Nuclear	0	0	0	0	0	0	0	0
	Large Hydro	5,444	5,444	5,444	5,444	5,444	5,444	5,444	5,444
	Pumped Storage	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047
	Gas	13,550	13,423	13,010	12,612	12,389	12,294	11,768	11,651
	Battery Storage	9,063	9,475	9,525	9,675	9,824	9,973	10,122	11,948
SCE	Solar	27,780	29,726	30,375	33,014	35,653	38,293	40,932	43,204
	Wind	12,716	13,521	15,421	15,921	16,421	16,921	17,421	17,421
	Other Renewable	1,239	1,251	1,263	1,275	1,287	1,300	1,312	1,324
	Large Hydro	978	978	978	978	978	978	978	978
	Pumped Storage	877	877	877	877	877	877	877	877
	Gas	9405	9104	9094	9004	8955	8915	8915	8732
	Battery Storage	10,773	11,714	13,584	14,529	15,474	16,419	17,363	17,363
SDGE	Solar	1,812	1,848	1,873	1,913	1,953	1,992	2,032	4,082
	Wind	467	467	467	467	467	467	467	467
	Other Renewable	590	784	978	1,173	1,367	1,562	1,756	1,951
	Pumped Storage	42	42	42	42	42	42	42	42
	Gas	3803	3803	3803	3803	3753	3753	3753	3689
	Battery Storage	1,089	1,089	1,089	1,089	1,089	1,089	1,089	1,089

Table 33: Installed Non-CAISO Capacity by Resource Class, End of Year (MW)

Region	Solar	Wind	Other Renewable	Nuclear	Large Hydro	PSH	Gas	Coal	Battery Storage
Alberta	249	2,701	502		826		5,045	5,828	
Avista	19	608	151		1,096		342		1
AZPublicService	1,627	478	52	3,551			1,385		70
BANC	354		113		1,370		2,765		
BPA	1,462	2,730	434	1,151	20,153	331	1,659		13
BritishColumbia		517	1,145		15,263		349		
ChelanCountyPUD			0		1,819		0		
DouglasCountyPUD			0		840		0		
ElPasoElectric	122	53	52				514		
GrantCountyPUD			16		2,048		0		
IdahoPower	328	1,816	345		1,921		1,139		
IID	1,236		565		33		588		208
LDWP	1,249	341	170		285	1,424	3,040	634	
N_BajaCA		645	653				1,778		
Nevada	5,550	34	231		1,039		3,191	406	276
NWMT	177	1,724	184		679		0	1,506	
PacificorpEast	1,825	2,536	386		209		497	1,286	
PACWSouth	70	293	201		892		46		
PortlandGeneral	69	163	147		565		991		
PublicServiceCO	1,955	3,040	95			71	2,815	728	68
PublicServiceNM	754	694	54				697		44
PugetSound	18	358	179		244		482		6
SaltRiverProject	727		61		36	425	1,950		2
SeattleCL			17		2,020		0		

TacomaPower			97		857		0		
TIDC	4		17		148		455		
TucsonElectric	420	486	3			120	47		43
WAPA_CO	246	1,077	202		1,144	191	1,182		4
WAPA_LwrCO	572	9	50		2,727		1,514	1,537	83
WAPA_UprMO		473	11		120		0		

Gas demand forecasts are driven by the assumptions utilized. There is inherent uncertainty in these assumptions that can result in actual gas demand deviating from the forecast. PG&E has developed this section to help illustrate how changes in key assumptions could potentially impact gas demand. The assumptions assessed under uncertainty are building electrification (BE), hydrogeneration availability, and CAISO imports availability.

Building Electrification

BE is one of the most impactful drivers of future forecasted gas demand in California. PG&E utilized the BE assumption from its 2024 ALF for Northern California. To quantify the uncertainty in gas demand associated with BE, PG&E assessed how EG demand changes[10] relative to the Average Demand Year forecast for selected years. To quantify the changes, the 2023 CEC IEPR AAFS 2 and AAFS3 cases were used.

The AAFS2 case represents a “low” case where there is virtually no future appliance bans or building codes. The 2023 IEPR AAFS 3 case represents a “high” case where appliance bans and building codes are 100% realized. Since BE impacts are expecting to ramp up over time, the difference between these scenarios in the near-term is much lower than it is in the long term.

Table 34: EG Demand Under Building Electrification Scenarios

Scenario	Year	EG Demand (MDth/d)
Average Demand	2025	722
	2030	600
	2035	416
	2040	426
Low BE (AAFS2)	2025	721
	2030	583
	2035	347
	2040	251
High BE (AAFS3)	2025	818
	2030	650
	2035	531
	2040	558

10 To quantify the EG gas demand change, all other modelling assumptions (including renewable resources) were kept the same as the Average-year demand scenario.

Hydroelectric Generation Availability

Hydroelectric generation is a key driver in determining EG gas demand. In the High Demand Year case, hydro availability is represented by using an average of generation in 2015 and 2021, both historically dry years. Applying "dry year" conditions to hydro availability increases EG demand across the forecast period, due to both a reduction in within-CAISO hydroelectric generation and lower import availability in the NW (a system reliant in hydropower). Imports into CAISO during 2023 declined significantly compared to previous years (approximately 50% of 5-year average), in part due to dry hydro conditions in the NW. This interregional dynamic is a critical driver of EG demand within Northern California and CAISO at large. Table 35 below describes changes in hydropower generation and EG demand in both the Average and Dry Hydropower cases.

Table 35: Hydroelectric Generation and EG Demand Under Average and Dry Hydro Conditions

Scenario	Year	Avg Annual Generation (GWh)*	EG Demand (MDth/d)
Average Demand	2025	23,726	722
	2030	--	600
	2035	--	416
	2040	--	426
High Demand ("Cold/Dry")	2025	9,704	934
	2030	--	726
	2035	--	556
	2040	--	608

*Data is large hydro generation for CAISO. An average over the 4 modeled years is shown given that within each scenario hydrogeneration deviation year-to-year is less than 1%.

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III. Peak Day Forecast Methodology

III. Peak Day Forecast Methodology

This section describes forecasts for daily gas demand, including three winter forecasts (1-in-90 Abnormal Peak Day, 1-in-2-Year Cold Winter Day, and 1-in-10-Year Peak Winter Day) and an estimate of high gas demand on a summer day for illustrative purposes. These forecasts incorporate the appropriate weather year and hydroelectric generation conditions as described in the sections below.

Abnormal Peak Day

The Abnormal Peak Day (APD) forecast is a projection of demand under extreme weather conditions. PG&E defines an APD as a 1-in-90 year cold temperate event. The 1-in-90 temperature corresponds to a 28.2 degree F system weighted mean temperature across the PG&E system. Under an APD design scenario, PG&E is only required to ensure that it can supply enough gas to Core customers on the system.

The APD core forecast presented in the 2024 CGR is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under APD conditions. Please see attached reference “1-in-90 Narrative” from Marquette Energy Analytics for more detail on the APD forecast methodology.

Winter Peak Day Demand

The tables below provide winter peak day demand projections on PG&E’s system for both a 1-in-10-Year Peak Winter Day and a 1-in-2-Year Cold Winter Day.

Table 36: 1-in-10-Year Peak Winter Day Demand (MMcf/d)

Year	Core Unadjusted for BE	BE Modifier	Climate Change Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2024-2025	2,493	-2	0	2,491	509	1,186	4,186
2025-2026	2,501	-8	-2	2,491	512	1,021	4,024
2026-2027	2,509	-16	-5	2,488	516	915	3,919
2027-2028	2,517	-22	-8	2,487	518	974	3,979
2028-2029	2,526	-32	-11	2,483	513	972	3,968
2029-2030	2,534	-49	-14	2,471	508	989	3,968

The Core demand in the 1-in-10-Year Peak Winter Day Demand table is developed using the observed relationship between historical daily weather and core gas usage.

This relationship is then used to forecast the Core load under a 1-in-10 temperature scenario. Please see attached reference "1-in-10 Narrative" from Marquette Energy Analytics for more detail on the forecast methodology.

The Noncore, Non-EG forecast is the average daily December demand under 1-in-10 Cold and Dry conditions, modified to account for the historical relationship between Noncore, Non-EG gas demand on a peak winter day and an average winter day. Since the Noncore, Non-EG sector is largely Industrial which is not statistically sensitive to climate impacts, this forecast does not vary by weather scenario and is not affected by climate change.

Last, the EG, including the Sacramento Municipal Utility District (SMUD) projection, is in the 90th percentile for the months of December through February under 1-in-10 cold and 1-in-10 dry hydro demand conditions.

Table 37: 1-in-2-Year Cold Winter Day Demand (MMcf/d)

Year	Core Unadjusted for BE	BE Modifier	Climate Change Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2024-2025	2,200	-2	0	2,198	506	1,001	3,705
2025-2026	2,207	-8	-2	2,197	509	869	3,575
2026-2027	2,214	-16	-5	2,193	512	819	3,524
2027-2028	2,222	-22	-8	2,192	514	831	3,537
2028-2029	2,229	-32	-10	2,187	509	798	3,494
2029-2030	2,237	-49	-13	2,175	505	902	3,582

PG&E's methodology used in the development of the 1-in-2-Year Cold Winter Day table is largely similar to the 1-in-10-Year Peak Winter Day methodology. The main differences are in the temperature and hydroelectric generation conditions. As stated in the title, this table assumes 1-in-2-year, or average, temperature conditions which will result in a warmer high demand day than the 1-in-10-Year. For hydroelectric generation, this table assumes 1-in-2-year, or average, hydroelectric generation conditions which will result in less California Independent System Operator (CAISO) electric demand needing to be met by thermal resource generation.

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IV. Forecast Tables

IV. Forecast Tables

For Excel versions of the tables above, please see attachment “2024 CGR Workpaper Master Tables PUBLIC.xlsx” spreadsheet.

For a detailed PG&E gas demand forecast at annual and monthly granularity, please see attachment “2024 CGR Annual and Monthly PG&E On-System Demand Forecast.xlsx”.

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V. 1-in-90 Abnormal Peak Day Methodology

Marquette Energy Analytics

Pacific Gas & Electric

Pacific Gas and Electric Company

Report on the Design Day Study for Core

25-Apr-2024

Statement of confidentiality

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Executive summary

Pacific Gas & Electric (PG&E) retained Marquette Energy Analytics to perform a Design Day study for their Core territory. The purpose of a Design Day study is to forecast the quantity of natural gas expected to be used during an extreme cold winter day, a "Design Day".

The assumed weather conditions on a Design Day are the Design Day Conditions (DDC). DDCs are stated as a "1-in-N-year" condition, meaning that the condition is expected to be exceeded once every 'N' years. Marquette Energy Analytics presents the DDC as wind-adjusted temperature (TempW) and equivalently as a wind-adjusted heating degree day (HDDW).

PG&E elected to use 1-in-90-year DDC. Table 1 shows the corresponding TempW and HDDW for this condition. The DDC For Core is a TempW 28.2 or 36.8 HDDW. This means Marquette Energy Analytics expects one day that is at least as cold as 36.8 HDDW every 90 years.

Table 1 – Design Day Conditions in both TempW and HDDW.

1-in-90-year Design Day Condition

Design Day Condition	TempW	HDDW
Core	28.2	36.8

Marquette Energy Analytics forecasted the Core Design Day demand as if the DDC were to occur during the upcoming 2024-2025 winter through the 2033-2034 winter. The Core Design Day demand forecast for 2024-2025 is 3,144 MDth.

Table 2 – Design Day forecast by winter (MDth). Forecasts for winters out to the 2033-2034 winter are available in pgeDesignDay.xlsx.

Core Design Day forecast by winter

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Design Day Demand	3,131	3,144	3,154	3,164	3,174
95% Confidence Demand	3,247	3,260	3,270	3,279	3,290

In Table 2, the Design Day demand forecast is presented in two ways – as a standard *Design Day Demand* and a *95% Confidence Demand*. The standard forecast is the expected level of demand if the DDC occurs. The 95% confidence forecast is the level of demand for which there is a 95% probability that actual demand will not exceed if the DDC occurs.

This report reviews the details of Marquette Energy Analytics' Design Day estimation and forecasting methodology; including the collection of data, calculation of the DDC, detrending of historical demand data to account for customer growth and changes in customer composition and behavior, and the models used to calculate and forecast Design Day demand.

Calculation of Design Day Conditions

The calculation of the Design Day Condition (DDC), that is, the wind-adjusted temperature (TempW) or wind-adjusted heating degree days (HDDW) associated with a 1-in-N-year condition, is a statistical analysis of historical weather between 02-Jan-1950 and 08-Apr-2024. This analysis was limited to historical days between November 1st and March 31st.

A 1-in-90-year Design Day Condition (DDC) is a weather event that is expected to occur once every 90 years. For a 1-in-90-year event, there is a 1.1 chance of it occurring in any given year, and an approximately 63.4 chance of it occurring at least once in a 90-year period. Equivalently, there is a 36.6 chance of a 1-in-90-year event NOT occurring in a 90-year period. It is also possible for more than one 1-in-90-year event to occur in a 90-year period.

Weather data set

The weather data used in the analysis is sourced from WeatherBank/AccuWeather and the US National Oceanic and Atmospheric Administration (NOAA) back to 1950. While the data received from the sources is hourly, the values used in this study are daily average temperatures aligned to the gas day. For the Core territory, this means that the weather is the daily average temperature between 7 AM and 7 AM each day.

Weighted combination of weather stations

Most service territories do not have a single centrally located weather station that represents the weather of the entire territory. For this reason, Marquette Energy Analytics used data from an optimally weighted combination of weather stations to represent the service territory. The optimal weights for each weather station were calculated to minimize error when modeling natural gas demand. Specifically, Marquette Energy Analytics calculated the weights that minimize the Root Mean Squared Error (RMSE) of the regressions used to model demand.

An initial set of potential weather stations were selected based on geographic proximity to the service territory. An iterative optimization process was then used to select the optimal set of weights with the objective of minimizing the regression's RMSE.

The optimization process can select weather stations outside the geographic territory. Due to geographical barriers, imperfect sensors, and many other obstacles, no weather station is a perfect representation of an area. Using multiple weather stations often works as a better proxy to estimate weather in areas in between weather stations. The weighted combination of weather stations for Core are in Table 3 below.

Table 3 – Weighted Combination of Weather Stations for Core.

Weighted Weather Station Combination

Weather Station Name	Call Sign	Weight
Redding, CA	KRDD	0.042
Sacramento, CA	KSAC	0.395
Fresno, CA	KFAT	0.059
Oakland, CA	KOAK	0.180
San Jose, CA	KSJC	0.284
Salinas, CA	KSNS	0.040

Wind adjusted heating degree days (HDDW)

Marquette Energy Analytics has found that wind significantly improves the accuracy of demand estimates and forecasts, especially at colder temperatures. For this reason, wind is included in all of Marquette Energy Analytics' models and forecasts.

Similar to the wind chill effect people experience, buildings lose more heat on windier days. Wind-Adjusted Heating Degree Day (HDDW) approximates this effect and is expressed in Equation 1. This methodology for incorporating wind was developed internally by Marquette Energy Analytics and has been found to greatly reduce modeling error when compared to using HDD without wind.

Equation 1 – Wind-Adjusted Heating Degree Days (HDDW)

$$HDDW = \begin{cases} HDD \times \dfrac{72 + Wind}{80}, Wind > 8 \\ HDD \times \dfrac{152 + Wind}{160}, Wind \leq 8 \end{cases}$$

Note: Equation is based on wind speed represented in mph and base temperature in °F

Figure 1 illustrates the relationship between temperature, wind, and HDDW using historical weather for Core. Each dot represents a day of weather with temperature on the x-axis and wind on the y-axis. The red line in the plot represents all combinations of temperature and wind that produce the 1-in-90 DDC. Days to the right of or above the red line are events that are more extreme than the DDC.

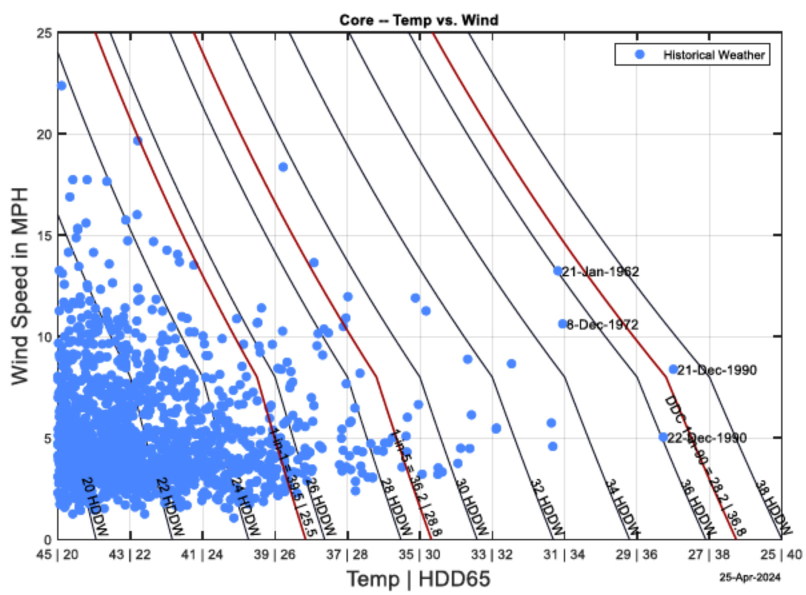


Figure 1: Temperature vs. Wind for Core.

Summary of Design Day Conditions

PG&E elected to use a 1-in-90-year DDC which is shown in Table 1. For Core The DDC is a TempW of 28.2 or 36.8 HDDW. Meaning that a wind-adjusted temperature of at least as cold as 28.2 is expected to occur at least once every 90 years.

Table 1 – Design Day Conditions

1-in-90 Year Design Day Condition

Design Day Condition (°F)	TempW	HDDW
Core	28.2	36.8

Acquisition and validation of load data

The demand (referred to equivalently as load or sendout) data used in Marquette Energy Analytics' analysis was provided by PG&E. Before any forecasting analysis began a thorough review of the data for possible errors and omissions was conducted. In consultation with PG&E corrections and adjustments were made as necessary. The load data used in this study was daily data aligned to the gas day from 27-Feb-1998 to 08-Apr-2024.

Detrending load data

When forecasting rare events, such as a Design Day, it is important to use a long history of data because it's more likely to include historical extreme cold events. Since customer base characteristics change over time due to many factors (growth in customer base, energy efficiency, changes in customer behavior, changes in customer class composition, etc.), using unadjusted older load data might cause a forecasting model to understate or overstate the Design Day demand if it were to occur today.

Therefore, older historical load data is "detrended" to ensure that forecasts based on the historical data reflect the current customer base characteristics. To do this, Marquette Energy Analytics created simple regression models to fit "windows" of historical data. The difference in the regression coefficients between different windows of data was used to estimate how much the customer characteristics, such as baseload and headload (use per HDDW), have changed. This information was then used to adjust older historical load data to act like current customer data. Data that has gone through his processes is called "detrended load".

Design Day forecasting models

At the core of Marquette Energy Analytics' detrending and forecast analysis are five slightly different linear regression models of natural gas demand. In addition to weather variables, the models use different combinations of day-of-week and day-of-year cyclical coefficients as explanatory variables. The base model is a five-parameter linear regression model with these parameters:

1) Constant
2) HDDW65 – Wind-Adjusted HDD with a reference temperature of 65°F
3) HDDW55 – Wind-Adjusted HDD with a reference temperature of 55°F
4) ΔMHDDW – Day-to-Day change in the average of HDDW55 and HDDW65
5) CDD65 – Cooling Degree Day (CDD) with a reference temperature of 65°F (CDD65 = MAX(0, Temp – 65)).

The five regression models are:

1) The base model trained on all days
2) The base model trained on just Monday through Thursday data
3) The base model plus day-of-week coefficients (13-parameters)
4) The base model with day-of-year coefficients (13-parameters)
5) The base model with both day-of-week and day-of-year coefficients (21-parameters).

These five models are used to detrend historical demand data as described in the previous section and then are used to create Design Day forecasts. For forecasting, three additional linear fits are calculated using the detrended load from Model #1 and #2. These three linear fits are:

1) A line fit through the 20% coldest days of Model #1 detrended data
2) A line fit through the 20% coldest Monday through Thursday of Model #1 detrended data
3) A line fit through the 20% coldest days of Model #2 detrended data

Each of the five component regression models, along with the three linear fit models is evaluated at the DDC, for a total of eight estimates. This technique of combining forecasts derived from different methods, often called "ensemble forecasting" has been shown to be more accurate than a singular forecast and is a well-accepted practice in the forecasting field. The mean value of a weighted gaussian mixture model ensemble of the eight estimates is used as the final Design Day estimate.

Winter severity adjustment

Marquette Energy Analytics has found that in warmer climates demand per HDDW is larger during colder winters than it is during an average winter. The eight forecasts described in the previous section assume that the Design Day will occur in an average winter. This works well for most areas but for Core this methodology understates the Design Day demand when it occurs in a colder winter.

Since extreme cold events typically occur during colder winters, a winter severity adjustment must be added to the Design Day estimate. For Core, a winter severity adjustment of 23 MDth was applied to each Design Day estimate.

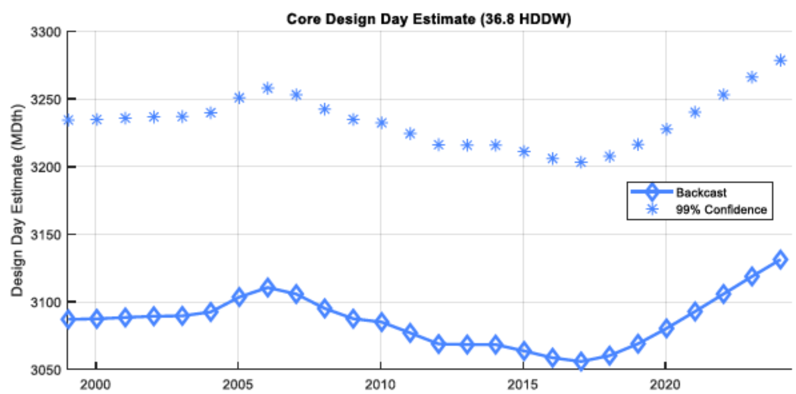
Summary of Design Day demand for prior years

This ensemble forecast is used to estimate what the Design Day demand would have been, if the Design Day condition of 36.8 HDDW, had occurred in each of the last 5 winters. The ensemble Design Day estimate for 2023-2024 is 3,131 Dth. The other previous winters are shown in Table 4 and Graph 2 below.

Table 4: Design Day estimate for prior winters (MDth). Estimates for winters back to the 1998-1999 winter are available in pgeDesignDay.xlsx.

Core prior winter Design Days

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Design Day Demand	3,080	3,093	3,106	3,119	3,131
95% Confidence Forecast	3,196	3,208	3,221	3,234	3,247



Graph 2: Design Day estimates for prior winters. Estimates for winters back to the 1998-1999 winter are available in pgeDesignDay.xlsx.

Design Day growth estimate for 2024-2025

Growth to the next heating season is accomplished by evaluating recent historical trends in baseload and heatload and usage per customer. This is done by weighting the one-year, two-year, and five-year baseload and heatload trends. From this Marquette Energy Analytics calculated the Core Design Day demand forecast for 2024-2025 to be 3,144 Dth.

95% Confidence forecast

The Design Day demand forecast is presented in two ways – a standard Design Day forecast of the expected level of demand, and a 95% confidence forecast.

The standard forecast is the expected demand if a 1-in-90-year weather event occurs. Assuming a normal distribution, there is a 50% probability that demand will exceed the forecast, and accordingly, a 50% chance that demand will be below the forecast.

The 95% confidence forecast includes an upward adjustment of the Design Day forecast by 2.0 standard deviations of the gaussian mixture model ensemble, which produces a forecast with an approximately 95% confidence level. This means if a 1-in-90 weather event occurs (36.8 HDDW), there is a 95% probability that the demand will not exceed the 95% confidence forecast.

In this analysis, the Core 95% confidence forecast for 2024-2025 is 3,260 MDth, which is 116 MDth (3.69%) greater than the standard 2024-2025 Design Day forecast. The choice to use the standard Design Day forecast or the 95% confidence forecast depends on the level of reliability needed from the forecast.

Design Day growth ten-year forecast

Marquette Energy Analytics also forecasted the Design Day growth out ten years. A long-term forecasting model was used to forecast changes in the baseload and heatload out ten years. This was accomplished with an ensemble of models that fit the historical data with linear and exponential trends of both the baseload and heatload demand.

Additionally, Marquette Energy Analytics incorporated economic components into the forecast. Specifically, forecasts of GDP from the Congressional Budget Office and commodity price forecasts derived from NYMEX Natural Gas futures were used.

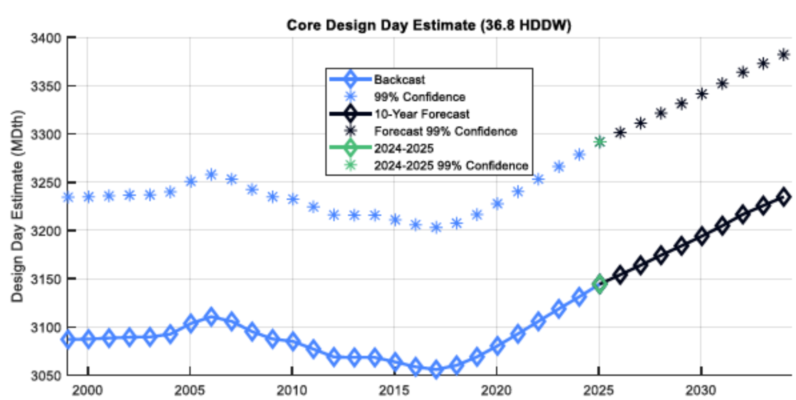
Design Day forecast summary

Marquette Energy Analytics forecasted the Core Design Day demand as if the DDC were to occur during the upcoming 2024-2025 winter through the 2033-2034 winter. The Core Design Day demand forecast for 2024-2025 is 3,144 MDth.

Table 2 – Design Day forecast by winter (MDth). Forecasts for winters out to the 2033-2034 winter are available in pgeDesignDay.xlsx.

Core Design Day forecast by winter

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Design Day Demand (Dth)	3,131	3,144	3,154	3,164	3,174
95% Confidence Forecast	3,247	3,260	3,270	3,279	3,290



Graph 3: Design Day forecasts by winter.

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VI. 1-in-10 Winter Peak Day Core Methodology

Marquette Energy Analytics

Pacific Gas & Electric

Pacific Gas and Electric Company

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25-Apr-2024

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The assumed weather conditions on a Design Day are the Design Day Conditions (DDC). DDCs are stated as a “1-in-N-year” condition, meaning that the condition is expected to be exceeded once every ‘N’ years. Marquette Energy Analytics presents the DDC as wind-adjusted temperature (TempW) and equivalently as a wind-adjusted heating degree day (HDDW).

PG&E elected to use 1-in-10-year DDC. Table 1 shows the corresponding TempW and HDDW for this condition. The DDC For Core is a TempW 34.6 or 30.4 HDDW. This means Marquette Energy Analytics expects one day that is at least as cold as 30.4 HDDW every 10 years.

Table 1 – Design Day Conditions in both TempW and HDDW.

1-in-10-year Design Day Condition

Design Day Condition	TempW	HDDW
Core	34.6	30.4

Marquette Energy Analytics forecasted the Core Design Day demand as if the DDC were to occur during the upcoming 2024-2025 winter through the 2033-2034 winter. The Core Design Day demand forecast for 2024-2025 is 2,588 MDth.

Table 2 – Design Day forecast by winter (MDth). Forecasts for winters out to the 2033-2034 winter are available in pgeDesignDay.xlsx.

Core Design Day forecast by winter

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Design Day Demand	2,577	2,588	2,596	2,605	2,614
95% Confidence Demand	2,692	2,703	2,712	2,720	2,729

In Table 2, the Design Day demand forecast is presented in two ways – as a standard *Design Day Demand* and a *95% Confidence Demand*. The standard forecast is the expected level of demand if the DDC occurs. The 95% confidence forecast is the level of demand for which there is a 95% probability that actual demand will not exceed if the DDC occurs.

This report reviews the details of Marquette Energy Analytics’ Design Day estimation and forecasting methodology; including the collection of data, calculation of the DDC, detrending of historical demand data to account for customer growth and changes in customer composition and behavior, and the models used to calculate and forecast Design Day demand.

Calculation of Design Day Conditions

The calculation of the Design Day Condition (DDC), that is, the wind-adjusted temperature (TempW) or wind-adjusted heating degree days (HDDW) associated with a 1-in-N-year condition, is a statistical analysis of historical weather between 02-Jan-1950 and 08-Apr-2024. This analysis was limited to historical days between November 1st and March 31st.

A 1-in-10-year Design Day Condition (DDC) is a weather event that is expected to occur once every 10 years. For a 1-in-10-year event, there is a 10.0 chance of it occurring in any given year, and an approximately 65.1 chance of it occurring at least once in a 10-year period. Equivalently, there is a 34.9 chance of a 1-in-10-year event NOT occurring in a 10-year period. It is also possible for more than one 1-in-10-year event to occur in a 10-year period.

Weather data set

The weather data used in the analysis is sourced from WeatherBank/AccuWeather and the US National Oceanic and Atmospheric Administration (NOAA) back to 1950. While the data received from the sources is hourly, the values used in this study are daily average temperatures aligned to the gas day. For the Core territory, this means that the weather is the daily average temperature between 7 AM and 7 AM each day.

Weighted combination of weather stations

Most service territories do not have a single centrally located weather station that represents the weather of the entire territory. For this reason, Marquette Energy Analytics used data from an optimally weighted combination of weather stations to represent the service territory. The optimal weights for each weather station were calculated to minimize error when modeling natural gas demand. Specifically, Marquette Energy Analytics calculated the weights that minimize the Root Mean Squared Error (RMSE) of the regressions used to model demand.

An initial set of potential weather stations were selected based on geographic proximity to the service territory. An iterative optimization process was then used to select the optimal set of weights with the objective of minimizing the regression's RMSE.

The optimization process can select weather stations outside the geographic territory. Due to geographical barriers, imperfect sensors, and many other obstacles, no weather station is a perfect representation of an area. Using multiple weather stations often works as a better proxy to estimate weather in areas in between weather stations. The weighted combination of weather stations for Core are in Table 3 below.

Table 3 – Weighted Combination of Weather Stations for Core.

Weighted Weather Station Combination

Weather Station Name	Call Sign	Weight
Redding, CA	KRDD	0.042
Sacramento, CA	KSAC	0.395
Fresno, CA	KFAT	0.059
Oakland, CA	KOAK	0.180
San Jose, CA	KSJC	0.284
Salinas, CA	KSNS	0.040

Wind adjusted heating degree days (HDDW)

Marquette Energy Analytics has found that wind significantly improves the accuracy of demand estimates and forecasts, especially at colder temperatures. For this reason, wind is included in all of Marquette Energy Analytics' models and forecasts.

Similar to the wind chill effect people experience, buildings lose more heat on windier days. Wind-Adjusted Heating Degree Day (HDDW) approximates this effect and is expressed in Equation 1. This methodology for incorporating wind was developed internally by Marquette Energy Analytics and has been found to greatly reduce modeling error when compared to using HDD without wind.

Equation 1 – Wind-Adjusted Heating Degree Days (HDDW)

$$HDDW = \begin{cases} HDD \times \dfrac{72 + Wind}{80}, Wind > 8 \\ HDD \times \dfrac{152 + Wind}{160}, Wind \leq 8 \end{cases}$$

Note: Equation is based on wind speed represented in mph and base temperature in °F

Figure 1 illustrates the relationship between temperature, wind, and HDDW using historical weather for Core. Each dot represents a day of weather with temperature on the x-axis and wind on the y-axis. The red line in the plot represents all combinations of temperature and wind that produce the 1-in-10 DDC. Days to the right of or above the red line are events that are more extreme than the DDC.

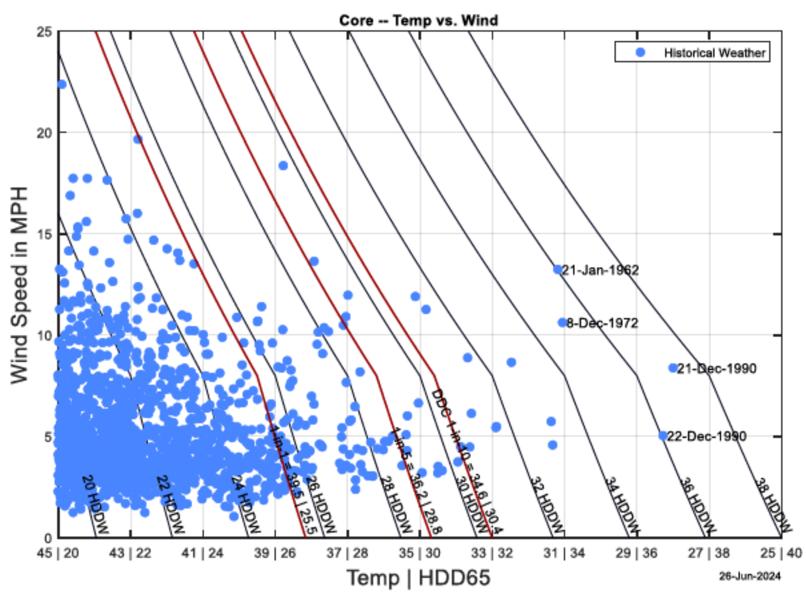


Figure 1: Temperature vs. Wind for Core.

Summary of Design Day Conditions

PG&E elected to use a 1-in-10-year DDC which is shown in Table 1. For Core The DDC is a TempW of 34.6 or 30.4 HDDW. Meaning that a wind-adjusted temperature of at least as cold as 34.6 is expected to occur at least once every 10 years.

Table 1 – Design Day Conditions

1-in-10 Year Design Day Condition

Design Day Condition (°F)	TempW	HDDW
Core	34.6	30.4

Acquisition and validation of load data

The demand (referred to equivalently as load or sendout) data used in Marquette Energy Analytics' analysis was provided by PG&E. Before any forecasting analysis began a thorough review of the data for possible errors and omissions was conducted. In consultation with PG&E corrections and adjustments were made as necessary. The load data used in this study was daily data aligned to the gas day from 27-Feb-1998 to 08-Apr-2024.

Detrending load data

When forecasting rare events, such as a Design Day, it is important to use a long history of data because it's more likely to include historical extreme cold events. Since customer base characteristics change over time due to many factors (growth in customer base, energy efficiency, changes in customer behavior, changes in customer class composition, etc.), using unadjusted older load data might cause a forecasting model to understate or overstate the Design Day demand if it were to occur today.

Therefore, older historical load data is "detrended" to ensure that forecasts based on the historical data reflect the current customer base characteristics. To do this, Marquette Energy Analytics created simple regression models to fit "windows" of historical data. The difference in the regression coefficients between different windows of data was used to estimate how much the customer characteristics, such as baseload and headload (use per HDDW), have changed. This information was then used to adjust older historical load data to act like current customer data. Data that has gone through his processes is called "detrended load".

Design Day forecasting models

At the core of Marquette Energy Analytics' detrending and forecast analysis are five slightly different linear regression models of natural gas demand. In addition to weather variables, the models use different combinations of day-of-week and day-of-year cyclical coefficients as explanatory variables. The base model is a five-parameter linear regression model with these parameters:

1) Constant
2) HDDW65 – Wind-Adjusted HDD with a reference temperature of 65ºF
3) HDDW55 – Wind-Adjusted HDD with a reference temperature of 55ºF
4) ΔMHDDW – Day-to-Day change in the average of HDDW55 and HDDW65
5) CDD65 – Cooling Degree Day (CDD) with a reference temperature of 65ºF (CDD65 = MAX(0, Temp – 65)).

The five regression models are:

1) The base model trained on all days
2) The base model trained on just Monday through Thursday data
3) The base model plus day-of-week coefficients (13-parameters)
4) The base model with day-of-year coefficients (13-parameters)
5) The base model with both day-of-week and day-of-year coefficients (21-parameters).

These five models are used to detrend historical demand data as described in the previous section and then are used to create Design Day forecasts. For forecasting, three additional linear fits are calculated using the detrended load from Model #1 and #2. These three linear fits are:

1) A line fit through the 20% coldest days of Model #1 detrended data
2) A line fit through the 20% coldest Monday through Thursday of Model #1 detrended data
3) A line fit through the 20% coldest days of Model #2 detrended data

Each of the five component regression models, along with the three linear fit models is evaluated at the DDC, for a total of eight estimates. This technique of combining forecasts derived from different methods, often called "ensemble forecasting" has been shown to be more accurate than a singular forecast and is a well-accepted practice in the forecasting field. The mean value of a weighted gaussian mixture model ensemble of the eight estimates is used as the final Design Day estimate.

Winter severity adjustment

Marquette Energy Analytics has found that in warmer climates demand per HDDW is larger during colder winters than it is during an average winter. The eight forecasts described in the previous section assume that the Design Day will occur in an average winter. This works well for most areas but for Core this methodology understates the Design Day demand when it occurs in a colder winter.

Since extreme cold events typically occur during colder winters, a winter severity adjustment must be added to the Design Day estimate. For Core, a winter severity adjustment of 17 MDth was applied to each Design Day estimate.

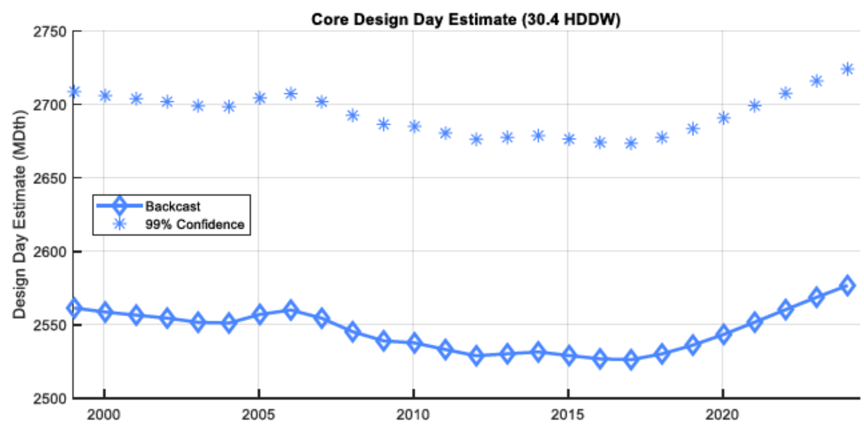
Summary of Design Day demand for prior years

This ensemble forecast is used to estimate what the Design Day demand would have been, if the Design Day condition of 30.4 HDDW, had occurred in each of the last 5 winters. The ensemble Design Day estimate for 2023-2024 is 2,577 Dth. The other previous winters are shown in Table 4 and Graph 2 below.

Table 4: Design Day estimate for prior winters (MDth). Estimates for winters back to the 1998-1999 winter are available in pgeDesignDay.xlsx.

Core prior winter Design Days

	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024
Design Day Demand	2,543	2,552	2,560	2,569	2,577
95% Confidence Forecast	2,659	2,667	2,676	2,684	2,692



Graph 2: Design Day estimates for prior winters. Estimates for winters back to the 1998-1999 winter are available in pgeDesignDay.xlsx.

Design Day growth estimate for 2024-2025

Growth to the next heating season is accomplished by evaluating recent historical trends in baseload and heatload and usage per customer. This is done by weighting the one-year, two-year, and five-year baseload and heatload trends. From this Marquette Energy Analytics calculated the Core Design Day demand forecast for 2024-2025 to be 2,588 Dth.

95% Confidence forecast

The Design Day demand forecast is presented in two ways – a standard Design Day forecast of the expected level of demand, and a 95% confidence forecast.

The standard forecast is the expected demand if a 1-in-10-year weather event occurs. Assuming a normal distribution, there is a 50% probability that demand will exceed the forecast, and accordingly, a 50% chance that demand will be below the forecast.

The 95% confidence forecast includes an upward adjustment of the Design Day forecast by 2.0 standard deviations of the gaussian mixture model ensemble, which produces a forecast with an approximately 95% confidence level. This means if a 1-in-10 weather event occurs (30.4 HDDW), there is a 95% probability that the demand will not exceed the 95% confidence forecast.

In this analysis, the Core 95% confidence forecast for 2024-2025 is 2,703 MDth, which is 116 MDth (4.48%) greater than the standard 2024-2025 Design Day forecast. The choice to use the standard Design Day forecast or the 95% confidence forecast depends on the level of reliability needed from the forecast.

Design Day growth ten-year forecast

Marquette Energy Analytics also forecasted the Design Day growth out ten years. A long-term forecasting model was used to forecast changes in the baseload and heatload out ten years. This was accomplished with an ensemble of models that fit the historical data with linear and exponential trends of both the baseload and heatload demand.

Additionally, Marquette Energy Analytics incorporated economic components into the forecast. Specifically, forecasts of GDP from the Congressional Budget Office and commodity price forecasts derived from NYMEX Natural Gas futures were used.

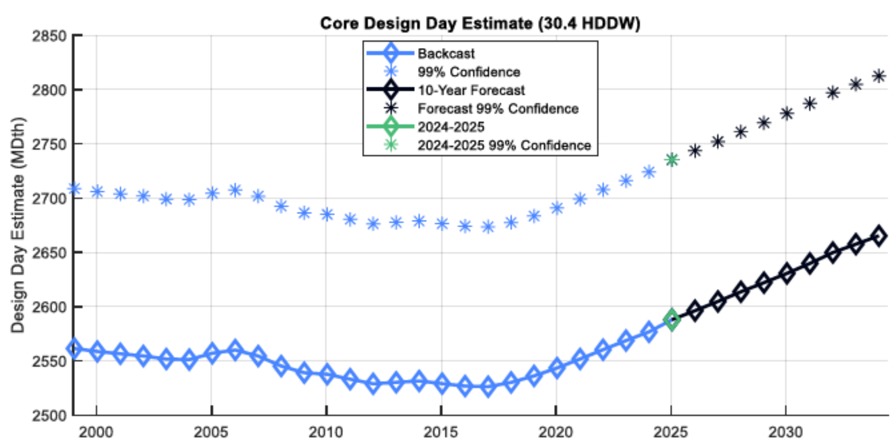
Design Day forecast summary

Marquette Energy Analytics forecasted the Core Design Day demand as if the DDC were to occur during the upcoming 2024-2025 winter through the 2033-2034 winter. The Core Design Day demand forecast for 2024-2025 is 2,588 MDth.

Table 2 – Design Day forecast by winter (MDth). Forecasts for winters out to the 2033-2034 winter are available in pgeDesignDay.xlsx.

Core Design Day forecast by winter

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Design Day Demand (Dth)	2,577	2,588	2,596	2,605	2,614
95% Confidence Forecast	2,692	2,703	2,712	2,720	2,729



Graph 3: Design Day forecasts by winter.

313 N. Plankington Ave.
Suite 206
Milwaukee, WI 53203

(414) 765-2855
marquetteenergyanalytics.com