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2024Q3 Load Forecast Methodology Overview

Our load forecast employs a combination of a bottom-up approach for energy usage and a top-down model for hourly system load shapes and peak demand. For weather-normalized monthly energy forecasts, we use Metrix ND software - an industry standard tool used by many of utilities, including SRP and PG&E - utilizing data from the SMUD billing system sales report known as SAP 21-Day Sales Report and Energy Management System (EMS) hourly data, along with economic and typical weather inputs from external consultants.

For hourly system modeling, Metrix LT is used to develop hourly, daily, monthly, and annual energy and peak forecasts over the forecast horizon. Short-term load impacts are primarily influenced by weather and economic factors, while long-term forecasts reflect customer growth and the adoption of new customer-owned technologies such as energy efficiency, building electrification, electric vehicles (EVs), photovoltaics (PV), and energy storage systems. Although we account for extreme weather in peak load scenarios, the current forecast is predominantly budget-oriented and does not include other scenario modeling.

Regression equations are developed and used to produce baseline sales and customer count forecasts.

Economic Drivers

We source national, state, and regional economic forecasts from S&P Global Market Intelligence, using indicators like Consumer Price Index (CPI), local Gross Domestic Product (GDP), employment, household growth, and personal income growth. These economic drivers influence both customer counts and sales projections.

Weather Adjustments

Because our territory's peak is largely driven by summer air conditioning loads, weather is a key factor for determining both energy peak and sales in our forecast. Our weather normalization adjusts historical data for temperature variations, relying on Cooling Degree Days (CDD) and Heating Degree Days (HDD) based on National Weather Service data. We use a composite temperature index for Sacramento, with "1-in-2" weather scenarios - meaning we consider average conditions expected to occur in half of all years - for typical weather conditions. Historical multipliers are used to model peak loads for extreme weather.

Non-Standard Commercial Growth

Forecasted load growth incorporates weather-normalized sales, reflecting overall system growth based on historical customer growth and economic trends.

When significant new commercial loads are anticipated with high certainty, non-standard commercial growth is adjusted by customer class to ensure accurate projections for large commercial demands. Examples of such non-standard loads include datacenters, UC Davis Health, and other large industrial expansions that can be projected with high certainty, beyond normal organic growth.

System Losses

System losses are calculated as the ratio of annual net system energy to annual retail sales and represents the difference of net system energy and final sales to retail customers. It reflects the distribution losses, unaccounted for energy and some billing adjustments. Net system energy is the total energy generation minus the house load at SMUD thermal power plants, and the generation from large private generation resources (which include large combined heat power systems (CHPs), large PV's and Fuel cells). The loss factor fluctuates from year to year and is based on averaging the calculated loss factors from 2016-2020 or 4.55%.

Distributed Energy Technologies

Our Distributed Energy Strategy (DES) department plays a key role in forecasting various Distributed Energy Resources (DER) programs, including energy efficiency (EE), building electrification (BE), electric vehicles (EVs), rooftop Photovoltaics (PV), and customer-owned energy storage systems (battery storage). SMUD-operated resources, such as community solar, are treated as supply-side resources and are excluded from the load forecast. DER impacts are incorporated from 2025 onward, with a detailed breakdown of assumptions reflected in the 2024 Load Forecast.

1. Energy Efficiency (EE)

Programs include Advanced Commercial Solutions, Express Energy Solutions, Complete Energy Solutions, Home Electricity Reports, Appliance Efficiency, Whole House Performance, and Multi-family Retrofit. Energy Efficiency (EE) programs reduce energy sales, and only approximately 40% of the EE impact is applied to the load forecast. This is because SMUD uses the statistically adjusted end-use model/approach that considers EIA data on average use per appliance (typically declining over time) and appliance saturation which may overlap with SMUD's long-standing EE program savings. EE load shapes are derived from both in-house and external consultant data. They are adjusted periodically and allocated by rate class and program participation history.

2. Photovoltaics (PV)

The PV forecast, based on data from external consultants and Power Clerk system, estimates the impact of new behind-the-meter systems. Residential PV systems are forecasted to average approximately 3 kW for new homes and 6 kW for existing homes, with PV impacts reducing sales. Incremental PV systems assume a 20% capacity factor with a 1% annual degradation. Hourly PV impacts are derived from actual customer metered data.

For the 2025 update, we plan to transition away from reliance on an external consultant forecast to reduce costs and leverage the wealth of in-house data available.

3. Electric Vehicles (EVs)

The forecast focuses on light-duty vehicles (LDVs), defined as vehicles under 6,000 lbs., with forecasts reflecting California's zero-emission vehicle goals which assumes a modest increase in sales to align with the executive order for 100% zero-emission vehicle sales by 2035. EV charging profiles impacts vary by time of day and location. At-home charging peaks between midnight and 2 a.m., while workplace charging impacts occur during business hours. High-speed charging peaks in the late morning to afternoon. The forecast assumes an EV managed charging program to distribute load across nighttime hours and mitigate peak demand impacts. However, the success of this program depends on EV adoption and participation. EVs will increasingly impact peak demand if the nighttime peak exceeds the evening peak. Managed charging aims to prevent this outcome.

For 2025, we are moving towards utilizing data and work done with E3 for the Integrated Distributed Resource Plan (IDRP), which will incorporate policy changes observed in Q1 and early Q2 of 2025.

4. Building Electrification (BE)

Building electrification refers to the conversion of gas-powered appliances to electric ones. This is part of California's initiative to reduce greenhouse gas emissions. The load forecast assumes that 20% of new homes will be electric heat starting in 2023 and reach 100% by 2030. Load shapes are based on EPRI data for commercial and residential water heaters and furnaces. The winter heating season has the largest impact on the load, with minimal effects on summer peak hours.

5. Energy Storage

Customer-owned battery storage systems are included in the forecast. Batteries are expected to charge during the day and discharge during evening peak hours to take advantage of time-of-use (TOU) rates. Battery storage systems are assumed to have an approximate 85% efficiency due to losses during charging and discharging. SMUD-operated storage is excluded from the forecast, as it is treated as a supply-side resource.

6. Demand Response (DR Programs)

Demand response programs, such as PowerDirect (Commercial AutoDR) and My Energy Optimizer (Residential Thermostat, including CPP), along with curtailment contracts and the residential ACLM, have been in place in SMUD territory for several years. The system peak data used in the model embeds the impact of these programs, and their continuation is thereby assumed in the forecast modeling.

Demand response programs are expected to be 61 MW in 2024.

Distributed energy resources/load flexibility

Key metrics & milestones

	2023 Final	2024 Goal	YTD (July)	2024 Forecast
My Energy Optimizer Partner • Smart thermostats enrolled	23,802	38,435	26,926	30,000
My Energy Optimizer Batteries enrolled • Starter (TOD-optimized batteries) • Partner+ (batteries enrolled in VPP)	326 80	506 580	553 107	600 208
Peak Conserve or NextGen ACLM (enrollments)	1,338	6,500	1,542	1,700
Commercial PowerDirect (MW enrolled)	21.2	22.7	27.5	29.8
Total MW	45.8	62.9	55.3	60.9

Note: All numbers are cumulative.

Program milestones:

- MEO Partner+ Battery Storage Virtual Power Plant (VPP) program changes
- MEO Partner Smart Thermostat program refinement
- PowerDirect program growth

Looking ahead:

- Continue scaling of key programs
- Increased focus on battery storage
  - Expansion of MEO Partner+
  - Multi-family installations
  - Planning for commercial VPP
- Operationalization and integration of portfolio resources

As this number grows, we are looking to improve the modeling of the load reduction.

Tables and Charts

- Peak Data
  - System Annual Peak (1 in 2, 1 in10)[1]
  - System Annual Peak Impact from DERs for Peak (1 in 2)
- Energy Data (Net Managed)
  - System Annual Energy
  - System Annual Energy impact from DERs

[1] A "1-in-10" peak weather scenario represents more extreme conditions—meaning there's about a 10% probability those conditions would occur in a given year (on average, once every ten years). This contrasts with a "1-in-2" peak scenario, which reflects more typical, or average, weather conditions (expected to occur in half of all years). Because "1-in-10" scenarios assume hotter peak summer conditions, the resulting peak demand is significantly higher than under the "1-in-2" scenario.

Peak Data (Gross Managed)[2]

[redacted]

[2] The common measure of SMUD's system load is Gross EMS, which includes electricity delivered to SMUD customers as well as any power used by SMUD's own power plants (station service) or generated and consumed on-site by customers using large CHP systems, PV systems over 500 kW, or fuel cells. Net EMS load removes station service and large customer-owned generation, thereby reflecting the portion of Gross EMS load that directly translates into sales.

[redacted]

[redacted]

Energy Data (Net Managed)[3]

[redacted]

[3] Net managed energy sales refer to electricity use that SMUD influences—through demand-response programs, time-of-day pricing, or similar programs—to help optimize overall system load and demand.