FY 2025 ELECTRIC UTILITY FINANCIAL PLAN

FY 2025 TO FY 2029

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SECTION 1: DEFINITIONS AND ABBREVIATIONS

CAISO California Independent System Operator
CARB California Air Resources Board
CIP Capital Improvement Program
CPAU City of Palo Alto Utilities Department
CPUC California Public Utilities Commission
CVP Central Valley Project
GWh a gigawatt-hour, equal to 1,000 MWh or 1,000,000 kWh. Commonly used for discussing total monthly or annual electric load for the entire city, or the monthly or annual output of an electric generator.
kWh a kilowatt-hour, the standard unit of measurement for electricity sales to customers.
kW a kilowatt, a unit of measurement used in reference a customer's peak demand (the highest 15 minute average consumption level in a month), which is used for billing large and mid-size commercial customers.
kV a kilovolt, one thousand volts, a unit of measurement of the voltage at which a section of the distribution system operates. The transmission system operates at 115-500 kV, and this is lowered to 60 kV in the sub-transmission section of the Electric Utility's distribution section, then 12 kV or 4 kV in the rest of the distribution system, and finally 120, 240, or 480 volts at the electric outlet.
MWh a megawatt-hour, equal to 1,000 kWh. Commonly used for measuring wholesale electricity purchases.
MW a megawatt, equal to 1,000 kW. Commonly used when discussing maximum electricity demand for all customers in aggregate.
PG&E Pacific Gas and Electric
REC Renewable Energy Certificate
RPS Renewable Portfolio Standard
Sub-transmission System: The section of the Electric Utility's distribution system that operates at 60 kV and which interfaces with PG&E's transmission system.
Transmission System: Sections of the electric grid that operate at high voltages, generally 115 kV or more. The voltage at the intersection of the Electric Utility's distribution system and PG&E's transmission system is 115 kV. The Electric Utility does not own or operate any transmission lines.
UCC Utility Control Center
SCADA Supervisory Control and Data Acquisition system, the system of sensors, communications, and monitoring stations that enables system operators to monitor and operate the system remotely.
WAPA, or **Western:** Western Area Power Administration, the agency that markets power from CVP hydroelectric generators and other hydropower owned by the Bureau of Reclamation.

SECTION 2: EXECUTIVE SUMMARY AND RECOMMENDATIONS

This document presents a Financial Plan for the City of Palo Alto (City) Electric Utility for the next five-year forecast, FY 2025 - 2029. This Financial Plan describes how revenues will cover the costs of operating the utility safely over that time while adequately investing for the future. It also addresses the financial risks facing the utility over the short term and long term and includes measures to mitigate and manage those risks.

SECTION 2A: OVERVIEW OF FINANCIAL POSITION

From July 2019 through April 2022 the City did not increase rates, to mitigate the economic impact of the COVID-19 pandemic on residents and businesses. In that time supply and distribution expenses increased $50 million (30%). The expense increases combined with pandemic-related electricity sales revenue declines created a $43 million shortfall in FY 2022. Some of this was related to the impacts of extreme drought and rising electricity market prices, and in response, the City activated the hydroelectric rate adjuster (E-HRA) in April 2022. In 2023 the City began increasing base rates to begin recovering costs, starting with a 5% rate increase on July 1, 2022. The intent was to use loans from the Electric Special Projects Reserve and what Operations Reserves remained to phase in rate increases gradually. But in late 2022 electricity market prices increased at unprecedented levels, leading to the need to increase the hydroelectric rate adjuster on January 1, 2023 to match the cost of replacing hydroelectric power with market power. On July 1, 2023 the City removed the hydroelectric rate adjuster while increasing its base electric rate 21%, the net result of which was a 5% rate decrease. This was possible due to heavy rains in the winter of 2022 / 2023 and the receipt of a judgment in a lawsuit related to the City's contract with the Western Area Power Administration for hydroelectric power from the Federal Central Valley Project. These two factors, combined with decreases in energy prices from the extreme winter 2022 / 2023 levels, enabled the City to replenish its reserves and stabilize rates at a level that fully recovers costs.

This forecast assumes long-term power prices continue to remain elevated over FY 2022 and earlier levels based on forward market price curve projections from independent commodity brokers. To reduce hydroelectric-related volatility in the future, staff is now making its rate projections assuming that long-term "normal" production from the City's hydroelectric resources is about 80% of historical average levels.

In contrast to last year's projection, this year's forecast includes significant one-time electric supply net revenues in FY 2024 and FY 2025 due to two factors. First, the utility had higher than average surplus electric energy sales due to the high hydroelectric generation associated with the heavy rains for winter 2022 / 2023 (for FY 2024). Second, the utility had significant revenue due to sales of surplus resource adequacy (generating capacity) under favorable market conditions that are not expected to continue long term. These one-time revenues are allowing the City to add to its hydroelectric stabilization reserve, which can be used to minimize the rate impacts of the additional costs associated with future dry years where hydroelectric generation is low.

There are also significant one-time costs in this forecast that were not in last year's forecast. They include large one-time costs associated capital investment, including a major Hanover Substation upgrade and grid modernization. There is also a timing issue associated with the first budget for grid modernization. This project was budgeted in FY 2024, but the debt issuance is not expected to take place until FY 2025, so this $25 million project is impacting reserves. This will require a one-year $20 million additional loan from the Electric Special Projects Reserve in FY 2024 rather than the $10 million repayment of a previous loan that was planned. This Financial Plan includes repayment of the total $30 million in outstanding Electric Special Projects Reserve loans in FY 2025.

Over the forecast period other costs are increasing as well. Cost increases include:

- Increases in transmission costs
- Increases in capital investment to replace aging infrastructure and modernize the electric grid
- Increased operations costs
- Debt service costs for grid modernization improvements and investments in fiber infrastructure to support AMI.

Because of these long-term cost increases rates are projected to increase the median residential bill 8% in FY 2025 and 5% per year for FY 2026 through FY 2029. For July 1, 2024 (FY 2025) staff has worked with a consultant to complete a cost of service analysis (COSA) that showed the need for rate decreases for non-residential customers ranging from 1% to 6% due to shifts in consumption patterns related to the COVID-19 pandemic. As a result, net sales revenue for FY 2025 is expected to remain about the same as in FY 2024. Because the regional economy is still recovering from that pandemic, leading to uncertainties in future consumption patterns, staff intends to continue to update the cost of service model in future years as the recovery proceeds. It is possible that a lower than average increase will be needed for residential customers in future years as the recovery continues and a higher one for non-residential customers.

There are some significant uncertainties in this forecast. Load is assumed to stay fairly flat in this forecast, with long-term declines in electric load offset by some load growth due to electrification and potential new data centers. If load growth exceeds expectations it could improve this forecast and reduce the size of future rate increases. On the other hand, if costs for electrification-related grid modernization and electrification programs exceed forecasts, which is quite possible given the high uncertainties involved in current cost projections, it could offset the benefits of increased load.

Due to the cash flow issue related to the budgeting of the first grid modernization project (in FY 2024) and the timing of the first debt issuance (in FY 2025), the Electric Utility's costs are high in FY 2024 and low in FY 2025. On average, though, the utility's costs for these two years is lower than FY 2023 levels. Expenses are expected to rise in FY 2026 through FY 2029, in part due to increasing power supply purchase costs, and in part due to grid modernization expenses. The average increase in utility costs from FY 2025 to 2029 is 3% annually[1] as shown in Table 1. Electric supply purchases continue to increase mainly due to rising transmission costs over the span of the financial plan and tightening requirements for resource adequacy.[2] Overall supply costs are projected to increase at 3% per year on average from FY 2025 to FY 2029. Operations and maintenance costs are projected to increase by about 2% per year on average due to both inflation as well as salary and benefits increases. Capital improvement costs, including debt service for grid modernization, are projected to increase 3.6% per year from FY 2025 through FY 2029.

Table 1: Electric Utility Expenses for FY 2023 to FY 2029

Expenses ($000)	FY 2023 (act)	FY 2024 (est)	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Power Supply Purchases	128,512	114,427	121,079	127,167	128,726	131,243	132,597
Operations	62,472	63,971	65,897	67,180	68,041	70,407	73,666
Capital - Rate Funded	21,656	66,884	0	15,143	14,671	12,688	13,089
Capital Debt Service	21	0	0	4,030	9,300	14,880	14,880
TOTAL	212,661	245,282	186,975	213,521	220,738	229,218	234,233

Table 2 below shows the proposed rates for FY 2025 and projections for FY 2026 through FY 2029. As noted above staff has completed a COSA and is proposing different rate changes for different customer classes in FY 2025 to align with the COSA results. Rates for non-residential customers will slightly decrease while rates for residential customers will increase. This is due to changes in consumption patterns related to the pandemic. Staff intends to continue to update the COSA model as the pandemic recovery continues which may result in additional rate adjustments by customer class in future years if consumption returns to historical patterns.

Table 2: Projected Electric Rates, FY 2025 to FY 2029

Projection	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Current	-6% to +8%[3]	5%	5%	5%	5%
Last Year	5%	5%	5%	5%	N/A

Staff is proposing several significant transfers in FY 2024 due to some very significant one-time revenues and expenses that have affected reserves. One-time revenues include a $24 million refund from the successful litigation against the Bureau of Reclamation for overcharges related

[1] Using the average of FY 2024 and FY 2025 for capital expenses.

[2] Resource adequacy represents the cost of maintaining generating capacity to fulfill the California Independent System Operator's capacity requirements assigned to the City.

[3] Rates for individual customers may vary significantly from this projection based on their consumption patterns.

to power purchases from the Central Valley Project as well as large one-time revenues related to resource adequacy sales, and large capital expenses related to grid modernization. As noted above, the capital expenses related to grid modernization are affecting the reserves in FY 2024, but this represents a temporary cash flow issue until the debt issuance to cover those expenses in FY 2025, at which time the reserves will be restored. However, as noted above, an internal loan from the Electric Special Projects Reserve will be required along with some inter-fund transfers. This will be added to the following $10 million in outstanding loans from prior years:

- In FY 2018 Council approved (Staff Report 8186[4]), a $10 million transfer from the Electric Special Projects (ESP) Reserve to the Operations Reserve to mitigate higher supply costs due to the drought, the costs of new renewable energy projects coming online and increasing transmission charges. $5 million was repaid in FY 2020
- In FY 2022 Council approved (Staff Report 13361, June 13, 2022), a $5 million transfer from the ESP Reserve to the Operations Reserve to avoid rate increases exceeding 5%.

This Financial Plan includes the repayment of all $30 million in loans in FY 2025.

In addition to the above transfers staff proposes to transfer $17 million to the Hydroelectric Stabilization Reserve in FY 2024 rather than $8.4 million (as was anticipated in the FY 2024 Electric Utility Financial Plan), bringing the balance to its target level and eliminating the chance that the hydroelectric rate adjuster will be activated if the winter of 2023/2024 ends up being dry. Rainfall patterns in California usually involve occasional above average hydroelectric years followed by multiple below-average years, so it is important to use the one-time revenues from wet years like the winter of 2022/2023 to replenish reserves and bring them above the target level.

Lastly, this plan includes a $5 million transfer in FY 2025 from the Distribution Operations Reserve to the CIP Reserve to bring it above its minimum level.

Table 4 shows the projected reserve transfers over the forecast period.

[4] https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/reports/city-manager-reports-cmrs/year-archive/2017/8186.pdf

Table 3: Reserves Starting and Ending Balances, Revenues, Expenses, Transfers To/(From) Reserves, Operations and Capital (CIP) Reserve Guideline Levels for FY 2023 to FY 2028 ($000)

			FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
	Starting Reserve Balances							
1		Supply Operations	44,463	15,601	27,652	26,757	26,337	25,855
2		Distribution Operation	(5,581)	6,921	12,020	14,317	14,429	15,362
3		CIP Reserve	880	880	5,880	5,880	5,880	5,880
4		Electric Special Projects	20,149	149	30,149	32,149	34,149	36,149
5		Hydro Stabilization	400	17,400	17,400	17,400	17,400	17,400
6		Cap and Trade Program	2,231	3,231	4,941	6,151	7,231	8,141
7		Public Benefits	5,673	7,431	9,033	10,569	12,032	13,422
8		Low Carbon Fuel Standard (LCFS)	6,713	4,053	1,486	-	-	-
9		Electrification Reserve	4,500	4,500	4,500	4,500	4,500	4,500
	Revenues							
10		Supply	145,323	142,902	133,822	133,976	136,567	139,122
11		Distribution	71,803	69,511	75,545	82,068	88,469	92,046
12		Cap and Trade Revenues	3,016	2,992	2,999	3,024	3,013	3,039
13		Public Benefits Revenues	4,780	4,690	4,584	4,551	4,520	4,488
14		LCFS Revenues	1,100	1,120	1,232	1,355	1,400	1,400
15		Electrification Reserve Repayments	-	-	-	-	-	-
	Transfers from Supply Operations Reserve to Other Reserves or to Distribution Fund							
16	From/(To)	Distribution Operation	(58,000)	26,000	-	2,000	2,000	2,000
17	From/(To)	Electric Special Projects	20,000	(30,000)	(2,000)	(2,000)	(2,000)	(2,000)
18	From/(To)	Hydro Stabilization	(17,000)	-	-	-	-	-
19	From/(To)	Cap and Trade	-	-	-	-	-	-
20: =16+17+18+19		Supply Operations Total	(55,000)	(4,000)	(2,000)	-	-	-
	Transfers from Distribution Operations Reserve to Other Reserves or to Supply Fund							
21	From/(To)	Supply Operations	58,000	(26,000)	-	(2,000)	(2,000)	(2,000)
22	From/(To)	CIP Reserve	-	(5,000)	-	-	-	-
23	From/(To)	LCFS	-	-	-	-	-	-
24: =21+22+23		Distribution Operations Total	58,000	(31,000)	-	(2,000)	(2,000)	(2,000)
	Expenses							
25		Supply Funded Expenses	(119,185)	(126,851)	(132,717)	(134,396)	(137,049)	(139,289)
26		Distribution Non-CIP Expenses	(50,482)	(52,153)	(58,105)	(65,285)	(72,848)	(74,969)
27		Distribution Planned CIP Expense	(66,884)	18,655	(15,143)	(14,671)	(12,688)	(13,089)
28		Cap and Trade Expenses	(2,016)	(1,282)	(1,789)	(1,944)	(2,103)	(2,309)
29		Public Benefits Expenses	(2,956)	(3,003)	(3,049)	(3,088)	(3,130)	(3,177)
30		LCFS Expenses	(3,759)	(3,687)	(2,718)	(1,355)	(1,400)	(1,400)
31		Electrification Reserve Expenditures	-	-	-	-	-	-
	Ending Reserve Balance							
32: =1+10+20+25		Supply Operations	15,601	27,652	26,757	26,337	25,855	25,687
33: =2+11+24+26+27		Distribution Operation	6,856	11,934	14,317	14,429	15,362	17,350
34: =3+22		CIP Reserve	880	5,880	5,880	5,880	5,880	5,880
35: =4+17		Electric Special Projects	149	30,149	32,149	34,149	36,149	38,149
36: =5+18		Hydro Stabilization	17,400	17,400	17,400	17,400	17,400	17,400
37: =6+12+19+28		Cap and Trade Program	3,231	4,941	6,151	7,231	8,141	8,871
38: =7+13+29		Public Benefits	7,497	9,119	10,569	12,032	13,422	14,733
39: =8+14+23+30		Low Carbon Fuel Standard	4,053	1,486	-	-	-	-
40: =9+15+31		Electrification Reserve	4,500	4,500	4,500	4,500	4,500	4,500
	Operations Reserve Guidelines (Supply)							
		Minimum	21,063	22,111	22,412	22,874	23,149	23,601
		Maximum	42,126	44,221	44,824	45,749	46,297	47,202
	Operations Reserve Guidelines (Distribution)							
		Minimum	10,800	11,701	12,742	14,084	14,526	14,763
		Maximum	17,736	19,382	21,303	23,821	24,530	24,824
	CIP Reserve Guidelines							
		Minimum	1,192	2,489	2,412	2,086	2,152	2,223
		Maximum	5,962	13,898	13,494	13,494	13,494	13,494

SECTION 2B: SUMMARY OF PROPOSED ACTIONS

Staff recommends the City Council adopt a Resolution:

1. Approving the Fiscal Year (FY) 2025 Electric Financial Plan, which includes the following actions;
    a. Amending the Electric Utility Reserves Management Practices, to direct staff to transfer to the CIP reserve, at the end of each fiscal year, any budgeted capital investment that remains unspent, uncommitted, and which is not proposed for reappropriation to the following fiscal year and to clarify how the Cap and Trade Program Reserve is adjusted each year.
    b. Approving the following transfers at the end of FY 2024:
        i. Up to $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve
        ii. Up to $17 million from the Supply Operations Reserve to the Hydroelectric Stabilization Reserve
        iii. Up to $58 million from the Supply Operations Reserve to the Distribution Operations Reserve; and
    c. Approving the following transfers in FY 2025:
        i. Up to $26 million from the Distribution Operations Reserve to the Supply Operations Reserve; and
        ii. Up to $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve
        iii. Up to $5 million from the Distribution Operations Reserve to the CIP Reserve
2. Approving the following rate actions for FY 2025:
    a. Changing retail electric rates E-1 (Residential Electric Service), E-2 (Small Non-Residential Electric Service), E-4 (Medium Non-Residential Electric Service), E-4 TOU (Medium Non-Residential Time of Use Electric Service), E-7 (Large Non-Residential Electric Service), and E-7 TOU (Large Non-Residential Time of Use Electric Service) by varying percentages depending on rate schedule and consumption with an overall revenue increase of 0.5% effective July 1, 2024;
    b. Decreasing the Net Surplus Electricity Compensation (E-NSE-1) rate to reflect 2023 avoided cost, effective July 1, 2024;
    c. Decreasing the Export Electricity Compensation (E-EEC-1) rate to reflect current projections of FY 2025 avoided cost, effective July 1, 2024; and
    d. Updating the Residential Master-Metered and Small Non-Residential Green Power Electric Service (E-2-G), the Medium Non-Residential Green Power Electric Service (E-4-G), and the Large Non-Residential Green Power Electric Service (E-7-G) rate schedules to reflect modified distribution and commodity components, effective July 1, 2024.

SECTION 3: DETAIL OF FY 2024 RATE AND RESERVES PROPOSALS

SECTION 3A: RATE DESIGN

The Electric Utility's rates are evaluated and implemented in compliance with cost of service requirements set forth in the California Constitution and applicable statutory law. This Financial Plan is based on staff's assessment of the financial position of the Electric Utility and updated using the methodology from the "City of Palo Alto Electric Cost of Service and Rate Study"[5] drafted by EES Consulting, Inc. in 2023/2024. The COSA is also based on design guidelines adopted by Council on November 11, 2021 (Staff Report 13546).

SECTION 3B: CURRENT AND PROPOSED RATES

The City adopted the current rates effective July 1, 2023, when the City increased the electric base rates by 21% while simultaneously removing the hydroelectric rate adjuster for a net decrease of 5% in the overall rate. This large rate change was needed because the City did not increase rates during the COVID-19 pandemic and instead drew down reserves. While using reserves mitigated larger increases during the pandemic, costs continued to rise and higher rates were needed to recover costs.

The City's consultant has completed a review and revision of the Electric Utility's Cost of Service study and rates. This study determined the rate changes needed for the residential and commercial classes to align them with the customer class cost of service identified in the study.. To ensure the median residential customer experiences no more than an 8% rate increase staff is recommending no revenue change for the electric utility this year, as discussed above. The current rates and proposed FY 2025 rates are reflected in Table 4 below:

[5] Staff Report 6857 http://www.cityofpaloalto.org/civicax/filebank/documents/52274

Table 4: Current and Proposed Electric Rates

	Current Rates	Proposed Rates (7/1/2024)	Change	
			$	%
E-1 (Residential)				
Tier 1 Energy ($/kWh)	0.17522	0.19337	0.01815	10%
Tier 2 Energy ($/kWh)	0.24666	0.20335	-0.04331	-18%
Customer Charge ($/day)		0.15250	0.15250	
E-2 & E-2-G (Small Non-Residential)				
Summer Energy ($/kWh)	0.26560	0.25211	-0.01349	-5%
Winter Energy ($/kWh)	0.18626	0.16415	-0.02211	-12%
Customer Charge ($/day)		0.18410	0.18410	
E-4 & E-4-G (Medium Non-Residential)				
Summer Energy ($/kWh)	0.16363	0.15387	-0.00976	-6%
Winter Energy ($/kWh)	0.12667	0.11018	-0.01649	-13%
Summer Demand ($/kW)	36.82668	45.29000	8.46332	23%
Winter Demand ($/kW)	24.16296	23.73000	-0.43296	-2%
Customer Charge ($/day)		3.73900	3.73900	
E-7 & E-7-G (Large Non-Residential)				
Summer Energy ($/kWh)	0.14561	0.13570	-0.00991	-7%
Winter Energy ($/kWh)	0.09856	0.08797	-0.01059	-11%
Summer Demand ($/kW)	39.08286	40.36000	1.27714	3%
Winter Demand ($/kW)	21.71270	27.79000	6.07730	28%
Customer Charge ($/day)		17.12210	17.12210	

Net Energy Metering Compensation Rates

The City operates two Net Energy Metering (NEM) programs. Solar customers served by the City of Palo Alto's (CPAU) original NEM program, also called NEM 1, are compensated at retail rates for electricity they export to the grid, and solar customers served by the NEM successor program, or NEM 2 (effective after the City reached its NEM 1 cap at the end of 2017), are compensated at the Export Electricity Compensation (EEC-1) rate for exported electricity.

Customers on the NEM 1 program who have chosen to have the value of any annual net generation they produced over the past 12 months credited back to their account do so under the Net Metering Net Surplus Electricity Compensation (E-NSE) rate. The Net Surplus Electricity Compensation rate represents the value of the City's avoided cost or value of customer-generated electricity in Palo Alto, including compensation for the energy, avoided capacity charges, avoided transmission and ancillary service charges, avoided transmission and distribution (T&D) losses, and renewable energy credits (RECs), or environmental attributes. Staff proposes decreasing the E-NSE-1 rate to $0.1427/kWh based on updated avoided cost calculations reflecting declines in long-term electricity market prices expected to continue into the future.

Under the City's NEM successor program, participating solar customers in Palo Alto are billed at the current retail rate for electricity drawn from the grid, and receive a credit for electricity they export to the grid at the Export Electricity Compensation (EEC-1) rate. This compensation rate also reflects the avoided cost or value of customer-generated electricity in Palo Alto, calculated on a forward-looking basis for the upcoming fiscal year. As shown in the table below, the current avoided cost for solar generation in Palo Alto is $0.1535/kWh, which is higher than the City's projected avoided cost, which requires the proposed NEM compensation rate (E-EEC) to decrease to $0.1420/kWh. This decrease in the overall avoided cost is driven by changes in electricity market prices.

Table 5: NEM Buyback Rates – Current vs. Proposed

Rate	Current $/kWh	Proposed $/kWh
Net Surplus Electricity (E-NSE)	$0.1535	$0.1427
Export Electricity (E-EEC)	$0.1685	$0.1420

Palo Alto Green (PAG) Program

The Palo Alto Green (PAG) program provides CPAU's commercial customers an opportunity to voluntarily pay a premium to receive renewable electricity credits to match their energy usage. Under this program, CPAU staff purchase and retire Green-e certified renewable energy certificates (RECs) in the wholesale market on behalf of PAG customers. This enables participating commercial customers to claim credit for the REC purchases in order to satisfy their corporate sustainability goals and meet federal "green certification" requirements.

The PAG charge is a pass-through charge; the revenue collected through the PAG rate premium is intended to fully recover the costs of administering the program. The PAG program has very low overhead costs (e.g., the cost of hiring an auditor to carry out an annual Green-e verification process for the program), so most of the program cost is the purchase cost of the RECs. In the past year the wholesale cost of Green-e certified RECs in the Western US market has remained relatively flat at around $7.00/REC. As such, the PAG rate premium should remain at $7.5 per 1,000 kWh block (.75 cents/kWh), enough to cover the cost of the RECs and overhead. The PAG rate premium is reflected on the Residential Master-Metered and Small Non-Residential Green Power Electric Service (E-2-G), the Medium Non-Residential Green Power Electric Service (E-4-G), and the Large Non-Residential Green Power Electric Service (E-7-G) rate schedules.

SECTION 3C: BILL IMPACT OF PROPOSED RATE CHANGES

Table 6 shows the impact of the proposed July 1, 2024 rate changes on the residential and non-residential bills for various consumption levels. The rate changes vary by customer class due to the completion of a cost of service analysis as noted in *Section 3B: Current and Proposed Rates*. Because of the addition of a customer charge and the changes in the design of the tiers for the E-1 customer class usage in this class varies widely depending on consumption, generally increasing for customers who use less electricity and decreasing for those who use more. The increase for the median residential customer is about 8%. This trend is expected to continue when the utility moves to time of use rates, which provides prices that vary by time of day rather than by how much electricity a customer uses in a month. It is worth noting, however, that increases among low users, while large in percentage terms, are small in absolute dollar terms (no more than $10.63 per month, and most low users will see less of an increase than that). For residents in need, staff is investigating whether it is possible to adjust the rate assistance program to offset these increases.

For more on comparisons of rates with surrounding agencies, see Section 4F: Competitiveness below.

Table 6: Impact of Proposed Electric Rate Changes on Customer Bills

Rate Schedule	Usage (kWh/mo)	Peak Demand (kW-mo)	Bill under Current Rates ($/mo)	Bill Under Rates Proposed 7/1/24 ($/mo)	Change	
					$/mo	%
E-1 (Residential)	300	N/A	$52.57	$62.65	$10.08	19%
	(Summer Median) 365	N/A	$66.46	$75.22	$8.76	13%
	(Winter Median) 453	N/A	$88.16	$92.24	$4.07	5%
	650	N/A	$136.75	$135.61	($1.14)	-1%
	1200	N/A	$272.42	$257.34	($15.07)	-6%
E-2 (Small Non-Residential)	1,000	N/A	$225.93	$213.73	($12.20)	-5%
E-4 (Medium Non-Residential)	160,000	274	$31,580	$30,693	($887)	-3%
	500,000	856	$98,680	$95,667	($3,014)	-3%
E-7 (Large Non-Residential	2,000,000	3,424	$348,247	$340,864	($7,383)	-2%

SECTION 3D: PROPOSED RESERVE TRANSFERS

Staff is proposing various reserve transfers to manage a one-year cash flow issue related to the grid modernization project. The first $25 million phase of the project was budgeted in the FY 2024 fiscal year, while the first debt issuance associated with the project is expected in FY 2025. This will have a negative impact on the distribution operation reserve in FY 2024. Without transfers from other reserves the distribution operations reserve would be significantly negative by the end of FY 2024. Fortunately, one-time revenues associated with a $24 million judgment from successful litigation against the Bureau of Reclamation (recognized in FY 2023 in the Supply Operations Reserve, leaving it close to the maximum reserve guideline) will help manage this cash flow issue, along with a one-year internal loan from the Electric Special Projects reserve. In the FY 2024 Electric Utility Financial Plan staff had intended to repay an earlier $10 million in internal loans from the Electric Special Projects Reserve in FY 2024. Instead, staff recommends postponing that loan repayment until FY 2025 and taking an additional $20 million in internal loans from the reserve for one year. The following transfers are proposed:

- In FY 2024, to keep the distribution operations reserve from going negative:
    - A transfer of $20 million from the Electric Special Projects Reserve to the Supply Operations Reserve
    - A transfer of $58 million from the Supply Operations Reserve to the Distribution Operations Reserve
- In FY 2025, to repay the internal loans from the Electric Special Projects Reserve and replenish the Supply Operations Reserve:
    - A transfer of $20 million from the Distribution Operations Reserve to the Supply Operations Reserve
    - A transfer of $30 million from the Supply Operations Reserve to the Electric Special Projects Reserve

The FY 2025 transfers are tentative and may need to be adjusted in the FY 2026 Financial Plan based on the results for the FY 2024 and FY 2025 fiscal years.

The electric utility is also experiencing one-time sales revenues and supply cost savings in FY 2024 related to high hydroelectric generation resulting from the rainy winter of 2022/2023. In addition, current market conditions are enabling the utility to realize higher than usual sales revenue related to surplus resource adequacy and REC sales in FY 2024, FY 2025, and FY 2026. Staff is recommending using these one-time revenues to replenish the hydroelectric stabilization reserve, bringing it to $17.4 million, a level which will allow the City to avoid having to activate the hydroelectric rate adjuster if upcoming winters are drier than average.

There are repayments of $2 million per year from FY 2026 through FY 2030 to the ESP Reserve for loans to the electric, gas, and fiber utilities for AMI investments.

The City maintains a Cap and Trade Program Reserve within the Electric fund to hold any revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the City's electric utility that are not spent within the fiscal year. Cap and Trade Program revenues are provided to the electric utility to support a wide variety of carbon reducing activities. Until the establishment of the REC Exchange program, adopted by Council in August 2020 (Staff Report #11556),[6] all of this Cap and Trade Program revenue was spent on purchasing renewable energy and none was held in reserve.

In accordance with Council's August 2020 direction, the City has begun selling City-owned renewable energy (Category 1 RECs, which mostly represent in-state renewable energy) and replacing them with purchased Category 3 RECs, which represent mostly out of state electricity. This exchange takes advantage of market conditions to reduce supply costs, fund electric utility programs and capital investment, and raise funds for local emissions reduction. On December 12, 2022[7] Council approved continuation of the program with 100% of revenue going to local emissions reduction. In accordance with Council policy, staff will fund the Cap and Trade Program Reserve with unspent revenues from the sale of carbon allowances freely allocated to the electric utility in an amount equal to 100% of each FY's Renewable Energy Credit (REC) Exchange program revenues, currently estimated to be between $0.7 million and $1.7 million going forward, for future local decarbonization projects.

Figure 8 (for Supply Fund Reserves) and Figure 9 (for Distribution Fund Reserves) in *Section 5E: FY 2025 – FY 2029 Projections* show the impact of these transfers on reserves levels. Table 7 shows the projected balance of each of the Electric Utility reserves for the period covered by this Financial Plan. See also: *Appendix A: Electric Utility Financial Forecast Detail*

[6]Staff Report 11556 https://www.cityofpaloalto.org/civicax/filebank/documents/78046
[7]https://cityofpaloalto.primegov.com/Public/CompiledDocument?meetingTemplateId=8715&compileOutputType=1 Staff Report 14735 Item 3, Agenda Item 3, *Utilities Advisory Commission Recommend the City Council Affirm the Continuation of the REC Exchange Program*, Staff Report #14375

Table 7: End of Fiscal Year Electric Utility Reserve Balances for FY 2023 to FY 2029

Ending Reserve Balance ($000)	FY 2023 (Act)	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Re-appropriations	253	253	253	253	253	253	253
Commitments	9,400	9,400	9,400	9,400	9,400	9,400	9,400
Low Carbon Fuel Standard (LCFS)	6,713	4,053	1,486	-	-	-	-
Cap and Trade	2,231	3,231	4,941	6,151	7,231	8,141	8,871
Underground Loan	727	727	727	727	727	727	727
Public Benefits	5,673	7,431	9,033	10,569	12,032	13,422	14,733
Special Projects	20,149	149	30,149	32,149	34,149	36,149	38,149
Hydro Stabilization	400	17,400	17,400	17,400	17,400	17,400	17,400
Capital	880	880	5,880	5,880	5,880	5,880	5,880
Rate Stabilization	-	-	-	-	-	-	-
Distribution and Supply Operations	38,882	22,522	39,672	41,074	40,766	41,216	43,037
Unassigned	-	-	-	-	-	-	-
TOTAL	85,306	66,046	118,941	123,602	127,837	132,588	138,449

SECTION 4: UTILITY OVERVIEW

This section provides an overview of the utility and its operations. It is intended as general background information to help readers better understand the forecasts in *Section 5: Utility Financial Projections* and *Section 6: Details* and Assumptions.

SECTION 4A: ELECTRIC UTILITY HISTORY

On January 16, 1900, Palo Alto began operating its own electric system. One of the earliest sources of Palo Alto's electricity was a steam engine, which was later replaced by a diesel engine in 1914 due to rising fuel oil costs. As the population and the demand for electricity continued to grow, CPAU connected to PG&E's system in the early 1920s. Power from PG&E proved more economical than the diesel engines, and by the late 1920s CPAU was using its own diesel engines only during peak demand periods. At that time CPAU owned 45 miles of distribution lines and the City used 9.7 GWh annually, less than 1% of today's annual consumption. The diesel engines remained in operation until 1948, when they were retired.

From 1950 to 1970 electric consumption in Palo Alto grew dramatically, just as it did throughout the rest of the country. In 1970 total annual sales were 602 GWh, twenty times the sales in 1950 (30 GWh). Some of that growth was related to a development boom in Palo Alto, which doubled the number of customers. Some was related to the proliferation of electric appliances, as evidenced by the fact that residential customers were using three times more electricity in 1970 than they had been in 1950. But the most notable factor was the growth of industry in Palo Alto during that time. By 1970, commercial customers were using 20 times more electricity per customer than they had been in 1950. These decades also saw several other notable events, including:

- 1964: CPAU entered into a favorably priced 40-year contract with the Federal Bureau of Reclamation to purchase power from the Central Valley Project (CVP), a contract which later was managed by the Western Area Power Administration (WAPA) an office of the Department of Energy created in the 1970s to market power from various hydroelectric projects operated by the Federal Government, including the CVP.
- 1965: The City began a long-term program to underground its overhead utility lines (Ordinance 2231).
- 1968: Palo Alto joined several other small municipal utilities to form the Northern California Power Agency (NCPA), a joint action agency intended to make the group less vulnerable to actions by private utilities and to enable investment in energy supply projects.

Palo Alto's first new power plant investment in over 50 years came in the mid-80s. Palo Alto joined other NCPA members to invest in the construction and operation of the Calaveras Hydroelectric Project on the Stanislaus River in the Sierra-Nevada Mountains. The project commenced operation in 1990. The 1980s also saw an increased focus on infrastructure maintenance. In 1987 the Utilities Control Center was built to house the terminals for a new System Control and Data Acquisition system, which enabled utility staff to monitor the distribution system in real time, improving response time to outages. CPAU also commenced a preventative maintenance and planned replacement program for its underground system in the early 1990s.

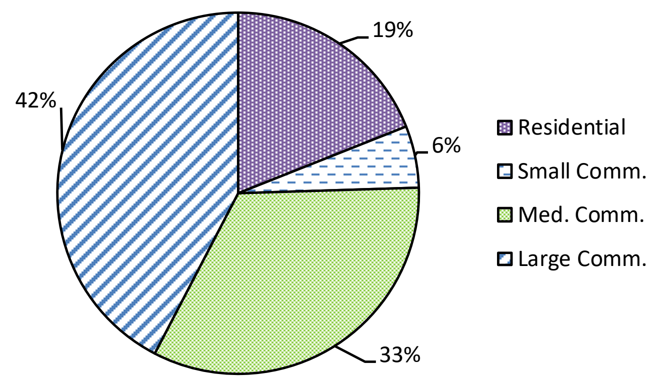
In the early 1990s the CPUC issued a ruling to deregulate the electric industry in California, and in 1996 the State legislature passed Assembly Bill 1890, which, among other things, created the California Independent System Operator (CAISO) to operate the transmission system and the Power Exchange to facilitate wholesale energy transactions. This restructuring was anticipated to bring lower costs to consumers, and while CPAU was not required to participate in the industry restructuring, in 1997 the Council approved a Direct Access Program for the Electric Utility[8] that enabled CPAU to sell electricity outside its service territory and allowed customers within CPAU's service territory to choose other providers. The utility unbundled its electric rates, creating separate supply and distribution components, which would enable customers to receive only distribution service while purchasing the electricity itself from another provider. The energy crisis in 2000 to 2001 led to the suspension of direct access by the CPUC in September 2001 as wholesale energy prices skyrocketed. The Electric Utility was less impacted than other utilities by the 2000 to 2001 energy crisis thanks to the Calaveras project and its contract with WAPA for CVP hydropower.

[8] *Implementation of Direct Access for Electric Utility Customers*, CMR:460:97, December 1, 1997

In 2001 CPAU began planning for the impacts associated with the new terms of its contract with WAPA, set to take effect in 2005. The previous contract had provided 90% of Palo Alto's power supply at favorable rates, and PG&E, as a party to the contract, had provided supplemental power to balance the monthly and annual variability of CVP generation. The new contract would provide only a third of Palo Alto's requirement, and the monthly and annual variability in CVP generation would be passed directly to Palo Alto. As a result, electric supply costs would increase and CPAU needed to manage its supply portfolio more actively. CPAU began purchasing power from marketers and investigated building a power plant in Palo Alto or partnering in the development of a gas-fired power plant elsewhere. Climate change was also becoming more of a concern to the community, and gradually CPAU shifted its focus to the procurement of renewable energy. In 2002 the Council adopted a goal of achieving 20% of its energy supply from renewables by 2015. Subsequently the City signed its first contract for renewable power, a contract for energy from a wind generator commencing deliveries in 2005. In 2011 the renewable energy goal was increased to at least 33% by 2015, and in 2013 the City adopted a plan to make its electric supply 100% carbon neutral, which it achieves through the combination of its carbon-free hydroelectric supplies, purchases of long-term renewable energy supplies, and short-term RECs to meet the balance of its needs.

SECTION 4B: CUSTOMER BASE

Figure 1: Customer Consumption By Class (FY 2023)



The City of Palo Alto's Electric Utility provides electric service to the residents, businesses, and other electric customers in Palo Alto. There are about 29,700 customers connected to the electric system, 25,600 (86%) of which are residential and 4,100 (14%) of which are non-residential. Residential customers consumed 157 gigawatt-hours (GWh) in FY 2022, approximately 19% of the electricity sold, while non-residential customers consumed 81% or 669 GWh. Residential customers use electricity primarily for lighting, refrigeration, electronics, and air conditioning.[9] Non-residential customers use most of their electricity for cooling, ventilation, lighting, office equipment (offices), cooking (restaurants), and refrigeration (grocery stores).[10]

As shown in Figure 1, large customer loads represent the biggest proportion of sales for the Electric Utility. The proportion of sales to large vs. small customers is greater than for the City's other utilities. For example, the largest customers (the 70 customers on the E-7 rate schedule) account for about 42% of CPAU's sales. The next largest customer group (the 890 non-residential customers on the E-4 rate schedule) represents another 33% of sales. In total, that means that about 3% of customers account for about three quarters of the electric load.

SECTION 4C: DISTRIBUTION SYSTEM

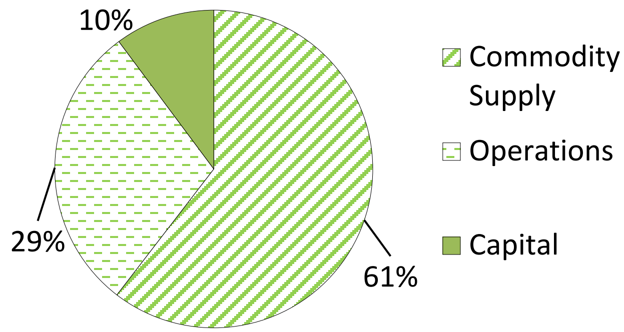
The Electric Utility receives electricity at a single connection point with PG&E's transmission system. From there the electricity is delivered to customers through nearly 472 miles of distribution lines, of which 211 miles (45%) are overhead lines and 261 miles (55%) are underground. The Electric Utility also maintains nine substations, roughly 2,000 overhead line transformers, around 1,100 underground and substation transformers, and the associated electric services (which connect the distribution lines to the customers' homes and businesses). These lines, substations, transformers, and services, along with their associated poles, meters, and other associated electric equipment, represent the vast majority of the infrastructure used to deliver electricity in Palo Alto.

[9] Source: Residential Appliance Saturation Survey, California Energy Commission, 2010

[10] Source: Statewide Commercial End Use Study, California Energy Commission report, 2006.

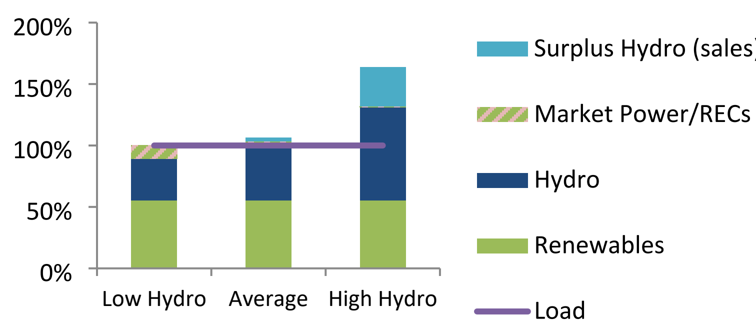
SECTION 4D: COST STRUCTURE AND REVENUE SOURCES

Figure 2: Cost Structure (FY 2023)



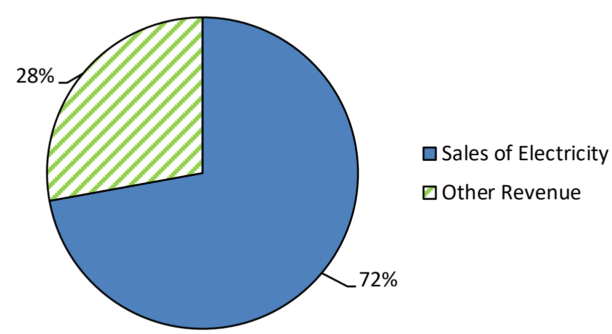
As shown in Figure 2, electric commodity purchases accounted for about 60% of the Electric Utility's costs in FY 2022. Operational costs represented about 30%, and capital investment was responsible for the remaining 10%. CPAU's non-hydro long-term commodity supply is heavily dependent on long-term contracts which have little variability in price. On average, costs for these long-term contracts are not predicted to increase as quickly as operations and CIP costs, and will steadily become a smaller proportion of the Electric Utility's costs. Staff projects commodity supply costs to be approximately 55% of total costs in FY 2028.

Figure 3: Hydroelectric Variability as a % of Load (FY 2023)



While average year purchase costs for the electric utility are predictable due to its long-term contracts, variability in hydroelectric generation can result in increased or decreased costs. This is by far the largest source of variability the utility faces. Figure 3 shows the difference in the annual load resource balance under high, projected, and low hydroelectric generation scenarios for FY 2022. Additional costs associated with a very low generation scenario can range from $8-20 million per year, depending on market prices. For the current hydroelectric risk assessment see *Section 5F: Risk Assessment and Reserves Adequacy*.

Figure 4: Revenue Structure (FY 2023)



As shown in Figure 4 the Electric Utility received about 72% of its revenue from sales of electricity and the remainder from connection fees, interest on reserves, cost recovery transfers from other funds for shared services provided by the electric utility, accounting entries that reflect things such as CPAU's participation in a prefunding program associated with its contract with WAPA, revenues from sales of surplus hydroelectric energy during wet years, as well as LCFS and Cap and Trade revenues. *Appendix A: Electric Utility Financial Forecast Detail* shows more detail on the utility's cost and revenue structures.

As discussed in *Section 4B: Customer Base*, nearly three quarters of the utility's electricity sales are to the 960 largest customers, which provide a similar share of the utility's revenue stream. About 25% of the utility's revenue comes from peak demand charges on large non-residential customers. Due to moderate weather and the prevalence of natural gas heating, however, loads (and therefore revenues) are very stable for this utility, without the large seasonal air conditioning or winter heating loads seen at some other utilities.

SECTION 4E: RESERVES STRUCTURE

CPAU maintains several reserves for its Electric Utility to manage various types of contingencies and for ease of reporting. It also maintains two funds, the Supply Fund and the Distribution Fund, to manage costs associated with electricity supply and electricity distribution, respectively. The City established this separation of supply and distribution costs as the City prepared to allow its customers a choice of electricity providers (referred to as "Direct Access") in the late 1990s and early 2000s. Though the 2000/2001 energy crisis halted these plans, CPAU continues to maintain separate funds to facilitate separation of supply and distribution costs in the rates. This could be important if California ever decides to broadly reintroduce Direct Access, and is useful for rate design as the nature of utility service evolves in response to higher penetrations of distributed generation. Thus, individual reserves may reside within a particular fund (for instance, Electric Special Projects is under Electric Supply) or be included within both funds (there are both Supply and Distribution Reserves for Commitments).

The summary below describes the various reserves, but see *Appendix B: Electric Utility Reserves Management Practices* for more detailed definitions and guidelines for reserve management:

- **Reserves for Commitments:** Reserves equal to the utility's outstanding contract liabilities for the current fiscal year. Most City funds, including the General Fund, have a Commitments Reserve.
- **Reserves for Reappropriations:** Reserves for funds dedicated to projects re-appropriated by the City Council, nearly all of which are capital projects. Most City funds, including the General Fund, have a Re-appropriations Reserve. This is currently an important reserve for all utility funds, but changes in budgeting practices will change that in future years, as described in Section 3C (Reserves Management Practices).
- **Electric Special Projects (ESP) Reserve:** This reserve was formerly called the Calaveras Reserve, which was accumulated during deregulation of California's electric system to fund the stranded costs associated primarily with the Calaveras hydroelectric resource and the California-Oregon Transmission Project. When that reserve was no longer needed for that purpose, the reserve was renamed and the purpose was changed to fund projects with significant impact that provide demonstrable value to electric ratepayers.

- **Hydroelectric Stabilization Reserve:** This contingency reserve is used for managing additional costs due to below average hydroelectric generation, or to hold surpluses resulting from above average hydroelectric generation.
- **Underground Loan Reserve:** This reserve is an accounting tool used to offset receivables associated with loans made through the underground loan program. It is adjusted according to principal payments made on those loans.
- **Cap and Trade Program Reserve:** This reserve tracks unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the electric utility, under the State's Cap and Trade Program. Funds in this Reserve are managed in accordance with the City's Policy on the Use of Freely Allocated Allowances under the State's Cap and Trade Program.
- **Low Carbon Fuel Standard (LCFS) Reserve:** This reserve tracks revenues earned via the sale of Low Carbon Fuel Credits allocated by the California Air Resources Board to the City, in accordance with California's Low Carbon Fuel Standard program.
- **Public Benefits Reserve:** CPAU's electric rates include a separate charge called the "Public Benefits Charge" which generates revenue to be used for energy efficiency, demand-side renewable energy, research and development, and low-income energy efficiency services. Any funds not expended in the current year are added to the Public Benefits Reserve for use in future years.
- **Capital Improvement Program (CIP) Reserve:** The CIP reserve can be used to accumulate funds for future expenditure on CIP projects, as well as to manage cash flow for ongoing capital projects. This reserve can also act as a contingency reserve for unforeseen capital expenses. This type of reserve is used in other utility funds (Water, Gas, and Wastewater Collection) as well.
- **Supply and Distribution Rate Stabilization Reserves:** These reserves are intended to be empty unless one or more large rate increases are anticipated in the forecast period. In that case, funds can be accumulated to spread the impact of those future rate increases across multiple years. This type of reserve is used in other utility funds (Gas, Wastewater Collection, and Water) as well.
- **Supply and Distribution Operations Reserves:** These are the primary contingency reserves for the Electric Utility and are used to manage yearly variances from budget for operational costs and electric supply costs (aside from variances related to hydroelectric generation). This type of reserve is used in other utility funds (Gas, Wastewater Collection, and Water) as well.
- **Unassigned Reserves (Supply/Distribution):** As in the other utility funds, these reserves are for any financial resources not assigned to the other reserves and are normally empty.

SECTION 4F: COMPETITIVENESS

For the median consumption level, the annual CPAU residential electric bill for calendar year 2023 was $964, which was $667 (41%) lower than the annual bill for a PG&E customer with the same consumption ($1,632) and approximately $136 (34%) higher than the annual bill for a City of Santa Clara customer ($718). However, both PG&E and Santa Clara did large rate increases on January 1, 2024. As shown in Table 8, below, the Palo Alto winter and summer median residential bills are only 18% and 11% higher than Santa Clara, which is about the same as the historical difference between the two. The high difference for CY 2023 reflects the fact that the City acted earlier than Santa Clara in recognizing increasing long-term commodity costs. This was something the City had to do due to low reserves resulting in part from avoiding rate increases through the COVID-19 pandemic to help residents manage the pandemic's economic impact. The PG&E bills based on the January 1, 2024 rates are 50% to 60% higher than Palo Alto, reflecting an increasing cost advantage for Palo Altans over utility customers in PG&E territory. The bill calculations for PG&E customers are based on PG&E Climate Zone X, which includes most surrounding comparison communities.

Table 8 presents sample median residential bills for Palo Alto, PG&E, and the City of Santa Clara (Silicon Valley Power) for several usage levels. Rates used to calculate the monthly bills shown below were in effect as of January 1, 2024.

Table 8: Residential Monthly Electric Bill Comparison (Effective 1/1/2024, $/mo.)

Season	Usage (kwh)	Palo Alto	PG&E	Santa Clara
Winter	300	52.56	126.03	49.02
	453 (Median)	88.16	191.88	74.93
	650	136.75	295.44	108.29
	1200	274.41	584.55	201.42
Summer	300	52.56	130.78	49.02
	(Median) 365	66.45	153.33	60.03
	650	136.75	314.76	108.29
	1200	282.18	603.87	161.54

SECTION 5: UTILITY FINANCIAL PROJECTIONS

SECTION 5A: LOAD FORECAST

Figure 5 shows a history of Palo Alto electricity consumption. Average electricity consumption grew from 1986 to 1998, then returned to 1986 levels by 2002. Since then, electricity consumption has declined slowly as a result of a continuing focus on energy efficiency, as well as the adoption of more stringent appliance efficiency standards and energy standards in building codes. Electrification will likely reverse some of this trend, although the pace of that impact is uncertain at this time. In recent years, some larger commercial customers have relocated operations or shifted to more light-commercial type usage. It is unknown how long this trend may continue, or what the longer-term impacts of COVID and work-from home policies might mean for commercial utilization in Palo Alto.

Figure 5: Historical Electricity Consumption

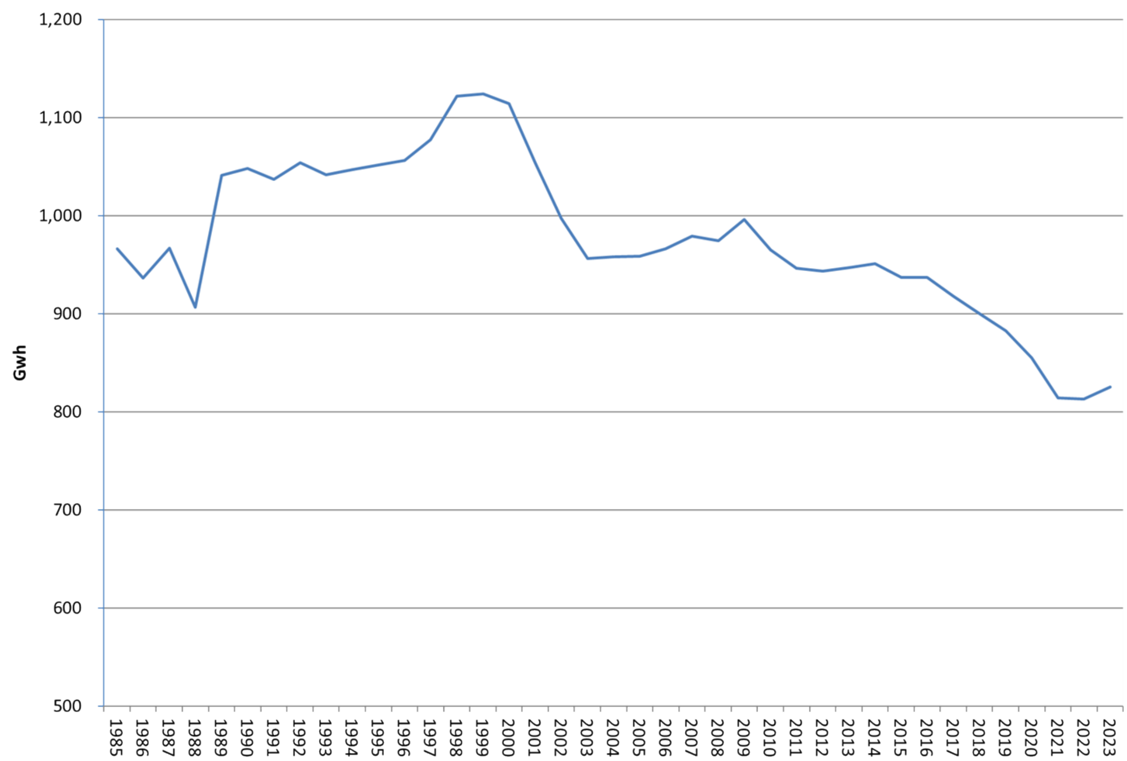
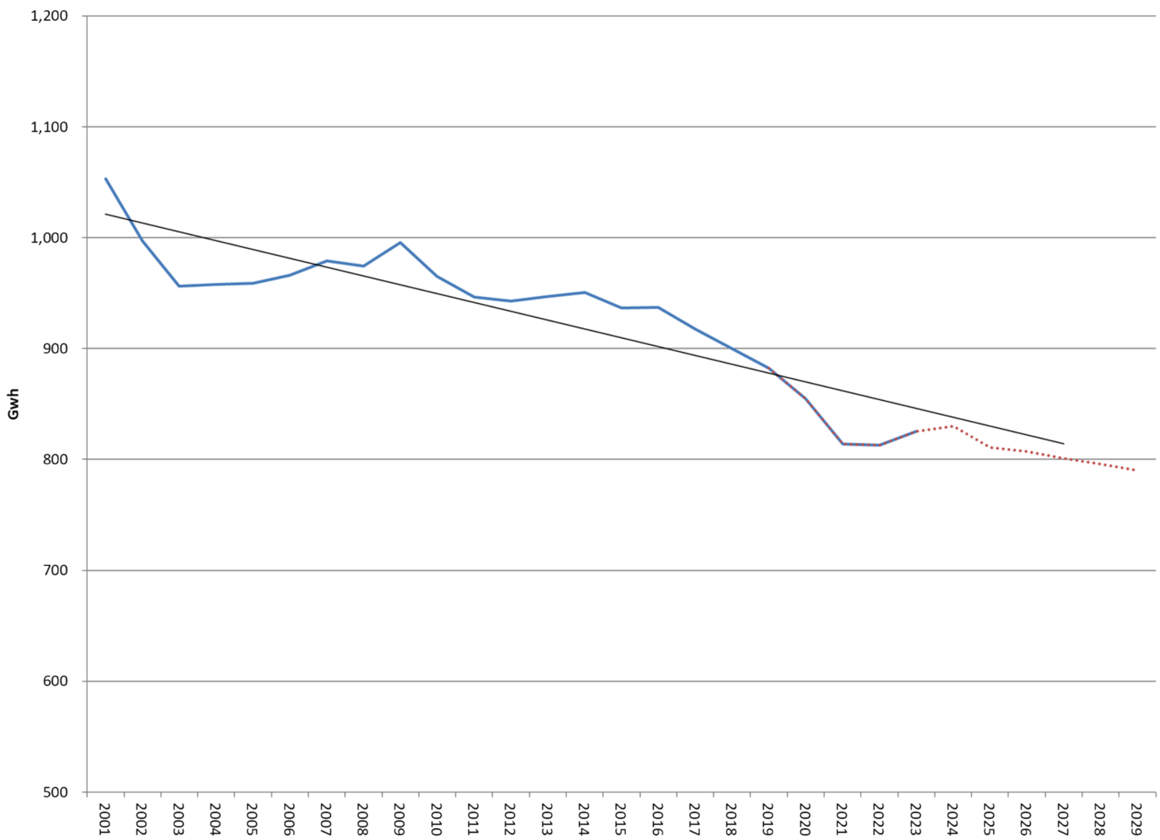


Figure 6 shows the forecast of electricity consumption through FY 2029. The solid black straight line is the long-term average trend of usage.

The small-dash red line represents the projected retail sales used in the financial forecast. Sales, which are depressed due to the economic effects of the pandemic, are assumed to recover to a level slightly above the long-term trend line. These projections are uncertain and will be revised if continuing sales change. Potential factors that may offset declining sales include a potential data center project. Building and vehicle electrification at a business as usual level is included in this forecast but large increases in the rate of building and vehicle electrification could increase sales further as well.

Figure 6: Forecasted Electricity Consumption



SECTION 5B: FY 2019 TO FY 2023 COST AND REVENUE TRENDS

As shown in *Appendix A: Electric Utility Financial Forecast Detail*, annual expenses for the Electric Utility increased significantly from FY 2019 to FY 2023. Electric supply costs increased as new renewable projects came online, and transmission costs rose and have continued to rise as improvements are made to the California grid. Capital investment and operational costs have increased due to construction inflation, increased investment in the electric system, and the cost of contract field crews to cover operational work due to challenges with vacancies.

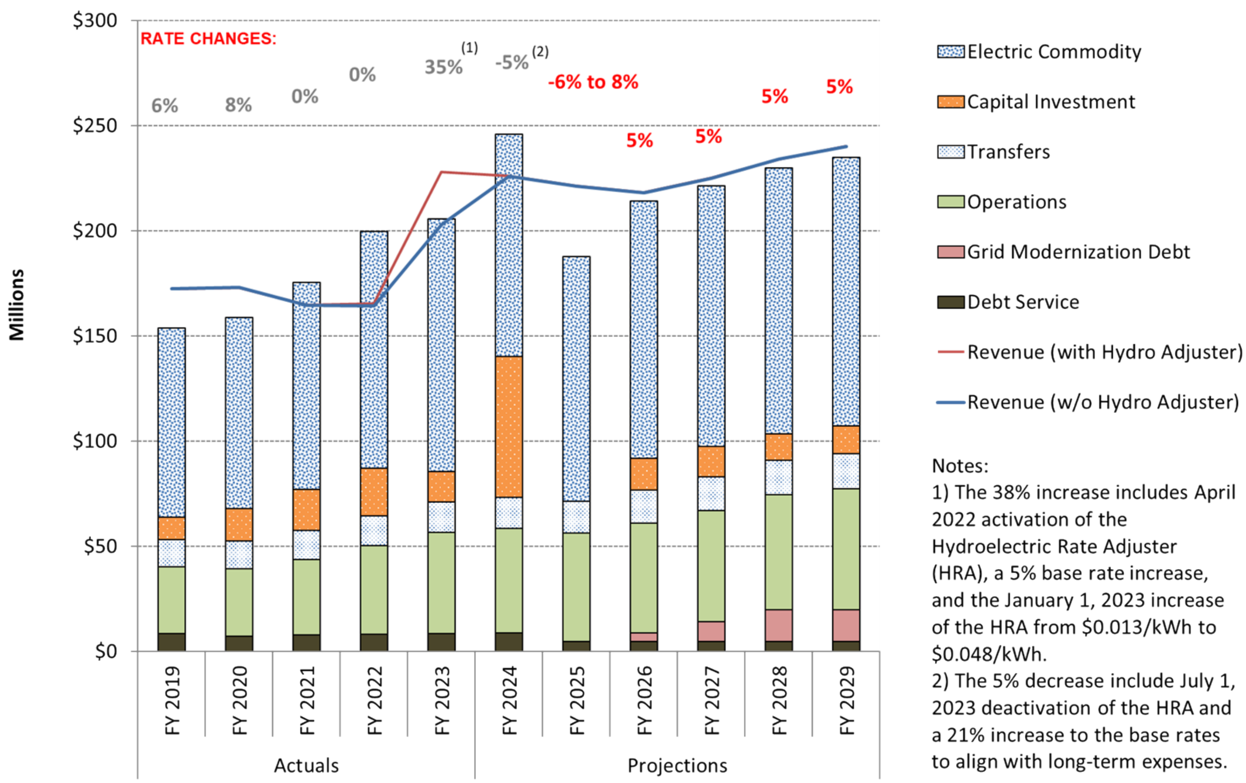
Section 6A: Electricity Purchases discusses the factors influencing electric supply expenses. During the drought in FY 2021 and FY 2022 costs increased due to a lack of hydroelectric generation. Better than average hydro conditions in FY 2019 led to lower than expected generation expenses as well as better than expected surplus energy revenues, but extreme drought followed. In FY 2023 the drought broke with record rainfall over the winter, but this was also accompanied by record high gas prices that drove electricity market prices high as well, offsetting the benefits of the rainfall.

The commodity and distribution costs for FY 2025 in Figure 7 are unusual due to one-time commodity revenues and savings and due to the timing of various capital investments and related debt issuances in FY 2024 and FY 2025. If using a more representative year (such as FY 2026), commodity costs can be seen to have increased 4% to 5% per year since FY 2020 and operational and capital investment costs can be seen to have increased 5% to 6% per year. The forecasted increases in distribution cost relate primarily to debt service for the grid modernization project as well as continuing construction inflation and other inflation. Combined, the utility's costs 4% to 5% per year on average for the last few years (after adjusting for the unusually low FY 2025 expenses)

Figure 7 shows the electric utility revenues, expenses, and proposed rate changes for the previous five years, the current year, and the projections for the next five years. The rate change percentages listed include the hydroelectric rate adjuster, which was activated in April 2022, increased in January 2023, and removed in July 2023. The removal of the hydroelectric rate adjuster was combined with a 21% base rate increase, leading to a 5% overall rate decrease**.**

The cost bars in FY 2024 reflect a one-time timing issue with the startup of the grid modernization project. The first year of spending was budgeted in FY 2024, but the first debt issuance will not take place until FY 2025 (this was to allow time for the City to apply for a grant, which it did not receive). It also reflects a one-time transfer in FY 2024 related to new customer investments.

Figure 7: Electric Utility Revenues, Expenses, and Rate Changes: Actual Costs through FY 2023 and Projections through FY 2029



SECTION 5C: FY 2023 RESULTS

FY 2023 revenues were $50 million higher than projections due to the activation of the hydroelectric rate adjuster ($26 million) and the receipt of the $24 million judgment related to a lawsuit against the Federal government related to the City's contract with the Western Area Power Administration. This was partially offset by net supply purchase costs that came in $28 million higher than projected due to extraordinarily high electric market prices. Operational costs came in about $8.7 million lower than projected due to savings in administration and demand side management (DSM) costs. Capital projects costs were lower than projections by $7.5 million.

Table 9 FY 2023, Actual Results vs. FY 2023 Financial Plan Forecast ($000)

	Net Cost/(Benefit)	Type of change
Higher revenues from Hydroelectric Rate Adjuster and judgment	($49,846)	Revenue increase
Higher electric supply costs	$28,099	Cost increase
Lower operational costs	($8,772)	Cost decrease
Lower than forecasted capital investment	($7,463)	Cost decrease
Net Cost / (Benefit) of Variances	**($37,982)**	

SECTION 5D: FY 2024 PROJECTIONS

Net revenues are expected to be $6.3 million lower than projected, but this includes wholesale revenues that are $20 million higher than forecasted due to better hydroelectric conditions than were anticipated in the FY 2024 Financial Plan forecast and higher prices for resource adequacy and REC sales. This is offset by a $26.6 million decrease in other revenues because the judgment for the lawsuit mentioned above was received in FY 2023 rather than FY 2024 as anticipated. Purchase costs are currently projected to be $3.6 million lower due to market prices moderating and hydroelectric conditions improving. Operations costs are projected to be $5.4 million lower than forecasted, but due to grid modernization and a rebuild of the Hanover Substation capital investment costs are projected to be $41 million more than previously forecasted. The net effect of these forecasted changes is $38 million in net impact to reserves, which offsets the $38 million in net benefit to reserves from FY 2023 results compared to forecasts.

Table 10 Change in Projected FY 2024 Results:
FY 2025 Financial Plan Forecast vs. FY 2024 Financial Plan Forecast ($000)

	Net Cost/(Benefit)	Type of change
Higher wholesale revenues	($20,234)	Revenue increase
Other revenues lower than forecasted	$26,605	Revenue decrease
Lower than forecasted supply costs	($3,592)	Cost decrease
Lower than forecasted operational costs	($5,473)	Cost decrease
Additional capital investment costs	$41,376	Cost increase
Net Cost / (Benefit) of Variances to Ops Reserve	**$38,681**	

SECTION 5E: FY 2025 – FY 2029 PROJECTIONS

As shown in Figure 7 above, From FY 2025 through FY 2029 increasing power supply costs combined with rising capital investment and debt service costs due to the grid modernization project are projected to lead to 5% per year projected rate increases in FY 2026 through FY 2029. A one-time transfer in FY 2026 related to the electric utility's share of the dark fiber system rebuild is also expected.

With California reservoirs filled and prices declining, power supply costs are expected to be lower in FY 2024 than previously forecasted, but hydroelectric revenue continues to vary annually and will be negatively affected by climate change over time. To reduce hydroelectric-related volatility in the future, staff is now making its rate projections assuming that long-term "normal" production from the City's hydroelectric resources is about 80% of historical average levels. Over the longer term, increasing transmission costs and tightening resource adequacy requirements are also expected to steadily increase electric supply costs.

The projected rate increases of 5% per year for FY 2026 through FY 2029 are expected to keep revenues in line with expenses. Staff recommends against raising rates significantly in FY 2025 to allow for changes in rates among customer classes to align with the recently completed cost of service analysis. This will allow the City to limit the rate changes for any customer class to 8% or less in FY 2025.

Reserves trends based on these revenue projections are shown in Figure 9 (for Supply Fund Reserves) and Figure 10 (for Distribution Fund Reserves), below. The Supply and Distribution Operations Reserves are projected to be slightly below the minimum level in FY 2024 but are expected to return to within guideline levels by the end of FY 2025.

This Financial Plan includes the restoration of the hydroelectric stabilization reserve from nearly empty to $17.4 million by the end of FY 2025, close to the reserve maximum and enough to allow the utility to absorb the increased costs associated with lower hydroelectric generation across multiple dry years. It also includes repayment of all internal loans from the Electric Special Projects Reserve by the end of FY 2025. And lastly, it includes significant interfund transfers in FY 2024 and FY 2025 to manage the impact of the cash flow issue associated with the startup of the grid modernization project (see *Section 3D: Proposed Reserve Transfers* for more detail).

The reserves charts below show significant increases in the Public Benefits and Cap and Trade reserves over the forecast period. This reflects that those funding sources are currently not fully utilized, but staff expects that to change as the City launches more electrification programs funded by those sources.

Figure 9: Electric Utility Reserves (Supply Fund): Actual Reserve Levels through FY 2023 and Projections through FY 2029

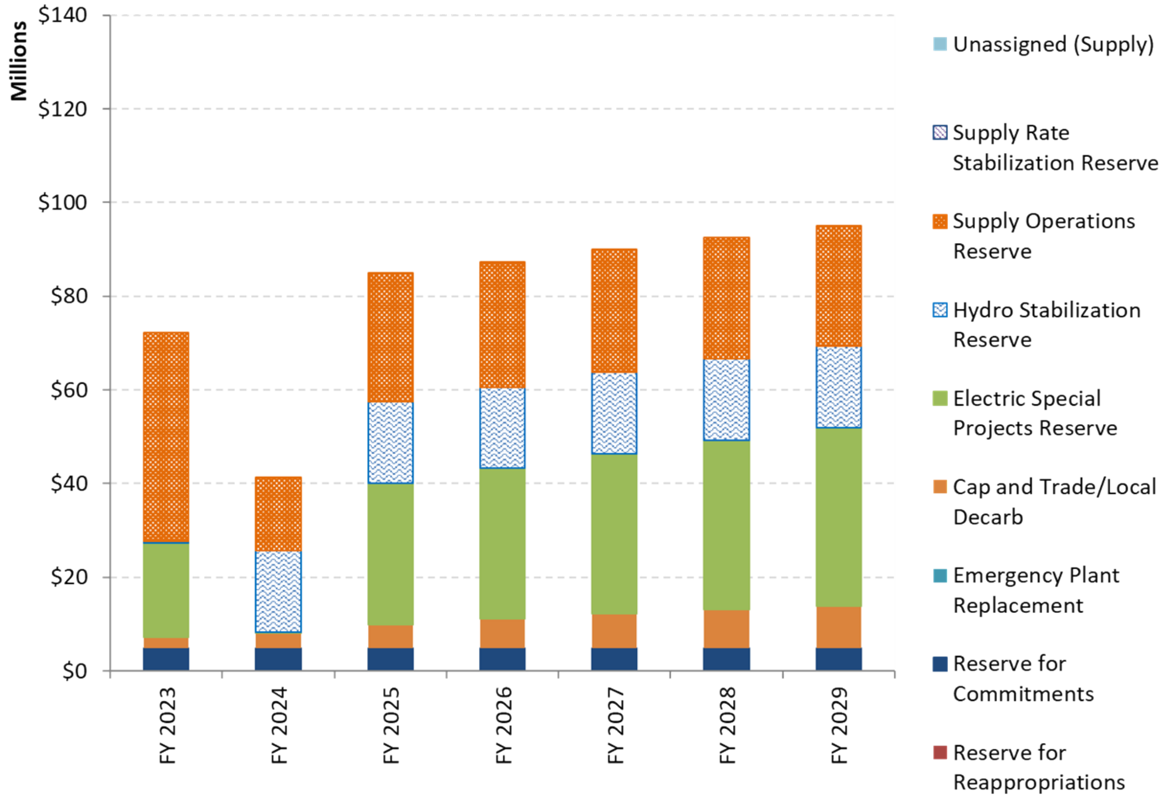
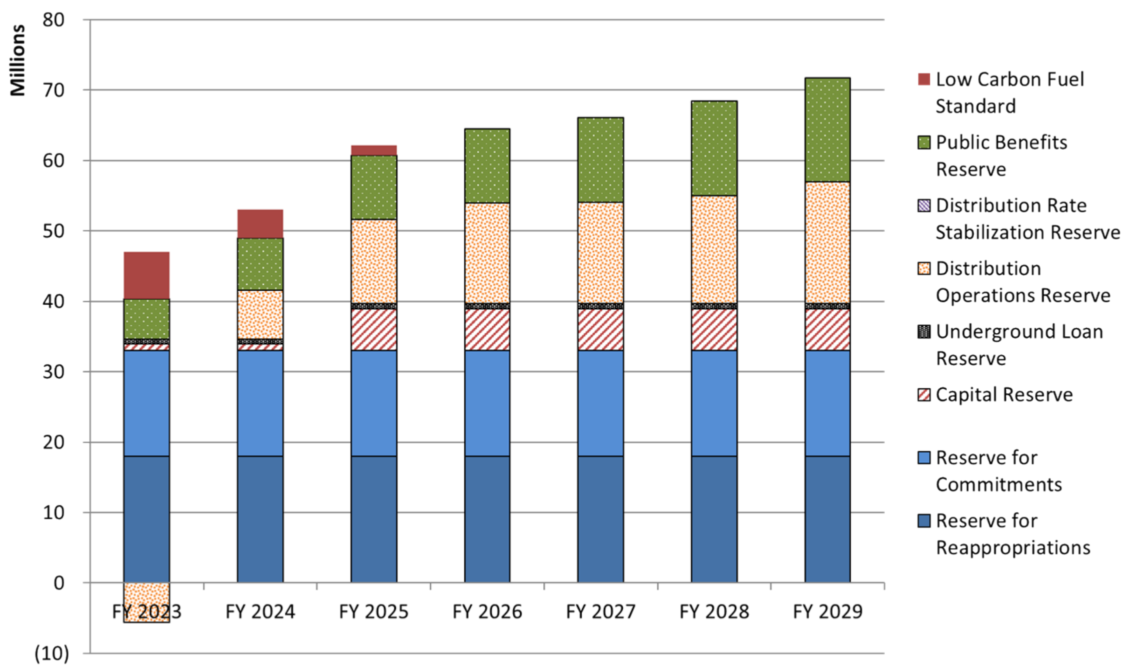


Figure 10: Electric Utility Reserves (Distribution Fund): Actual Reserve Levels through FY 2023 and Projections through FY 2029



SECTION 5F: RISK ASSESSMENT AND RESERVES ADEQUACY

The Electric Utility currently has two primary contingency reserves, the Supply Operations Reserve and the Distribution Operations Reserve. In addition, the Electric Utility has a Hydro Stabilization Reserve, an ESP Reserve, and a Capital Reserve, which can be utilized with Council approval.

There are a variety of risks associated with the Supply Fund related to resource generation variability, market price volatility, transmission cost increases, regulatory changes to market rules. Because of the high range of uncertainty in energy price predictions more than three years in the future, this risk assessment is only performed for the first two fiscal years of the forecast period. It is important to note that the likelihood of all these adverse scenarios occurring simultaneously and to the degree described in Table 12 is very low.

Table 12: Electric Supply Fund Risk Assessment

Categories of Electric Supply Cost Uncertainties	Estimates of Adverse Outcomes (M$)	Estimates of Adverse Outcomes (M$)
	FY 2025	FY 2026
1. Load Net Revenue	4.8	3.8
2. Hydro Production: Western & Calaveras	8.4	3.8
3. Renewable Production: Landfill, Wind, Solar, Geothermal	1.1	1.9
4. REC Purchases	0.5	0.5
5. REC Sales	3.8	2.8
6. Market Price	2.4	2.1
7. Resource Adequacy	3.2	1.1
8. Transmission/CAISO	4.8	5.0
9. Plant Outage	1.0	1.0
10. Western Cost	1.3	1.7
11. Legislative & Regulatory	0.0	0.0
12. Supplier Default+	0.2	0.2
Electric Supply Fund Risks	**31.6**	**23.9**

Of the risks faced by the Electric Utility's Supply Fund, the risk of a dry year with very low hydroelectric output is normally the largest, accounting for more than one-third ($8.4 million) of all the adverse cost uncertainty. Since the utility's costs for its hydroelectric resources are almost entirely fixed, costs do not decline when the output of those resources are low, but the utility needs to buy power to replace the lost output. The converse happens when hydroelectric output is higher than average.

Of the remaining risks for FY 2025, $4.8 million is related to potential transmission cost increases (above staff's current forecast). $4.8 million is related to the potential that total load (and the associated retail sales revenue) may be lower than projected. Other risks related to production from the City's renewable contracts and market prices for purchases and sales of energy and resource adequacy (Items 3, 4, 5, 6, and 7 above) total $11 million due to the unusually high market prices and surplus sales contract volumes in FY 2025.

As shown in Figure 11, staff projects the Supply Operations Reserve to drop below the minimum guideline levels in FY 2024 but return to within guideline levels by the end of FY 2025. Note that the high reserve level in FY 2023 is related to the timing of a $24M judgment from a lawsuit related to the allocation of costs of the Central Valley Project. These funds are being redistributed to other purposes in FY 2024, with the transfers resulting in a reduction in the Supply Operations Reserve. Figure 12 shows that the combined Hydro Stabilization and Supply Operations Reserves are projected to be above the risk assessment level through the forecast period.

Figure 11: Electric Supply Operations Reserve Adequacy

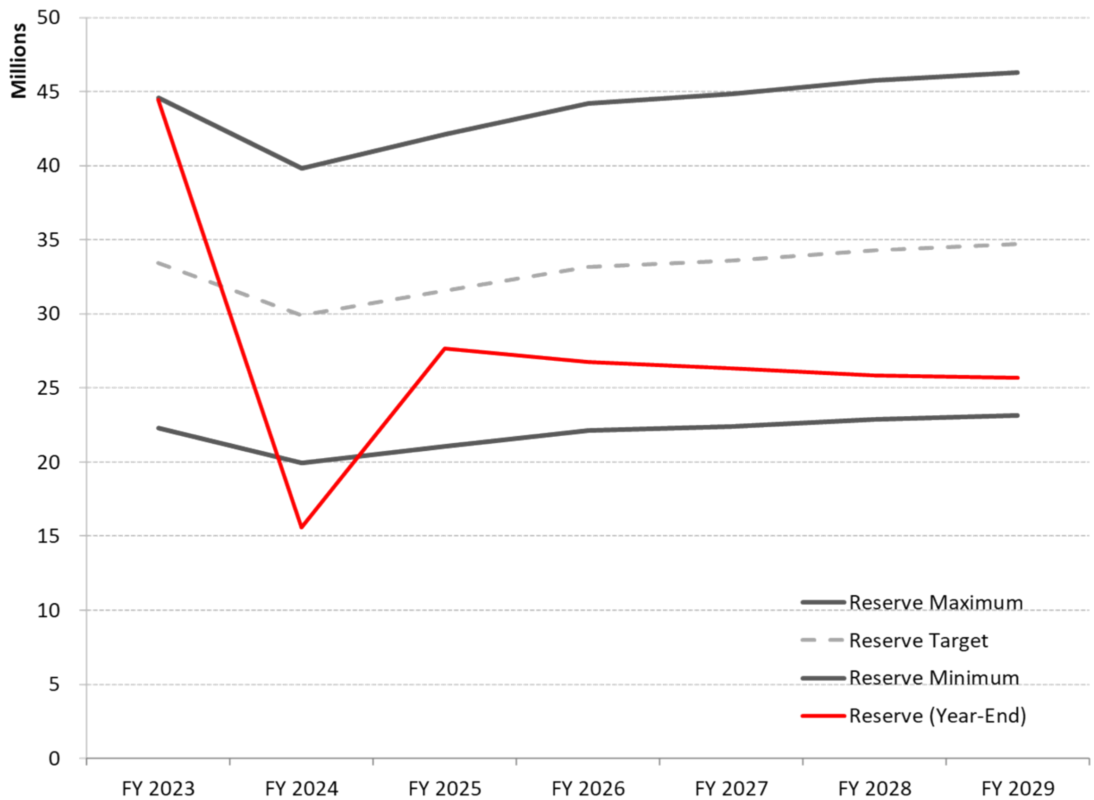


Figure 12: Adequacy of Supply Operations and Hydro Stabilization Reserves, Combined

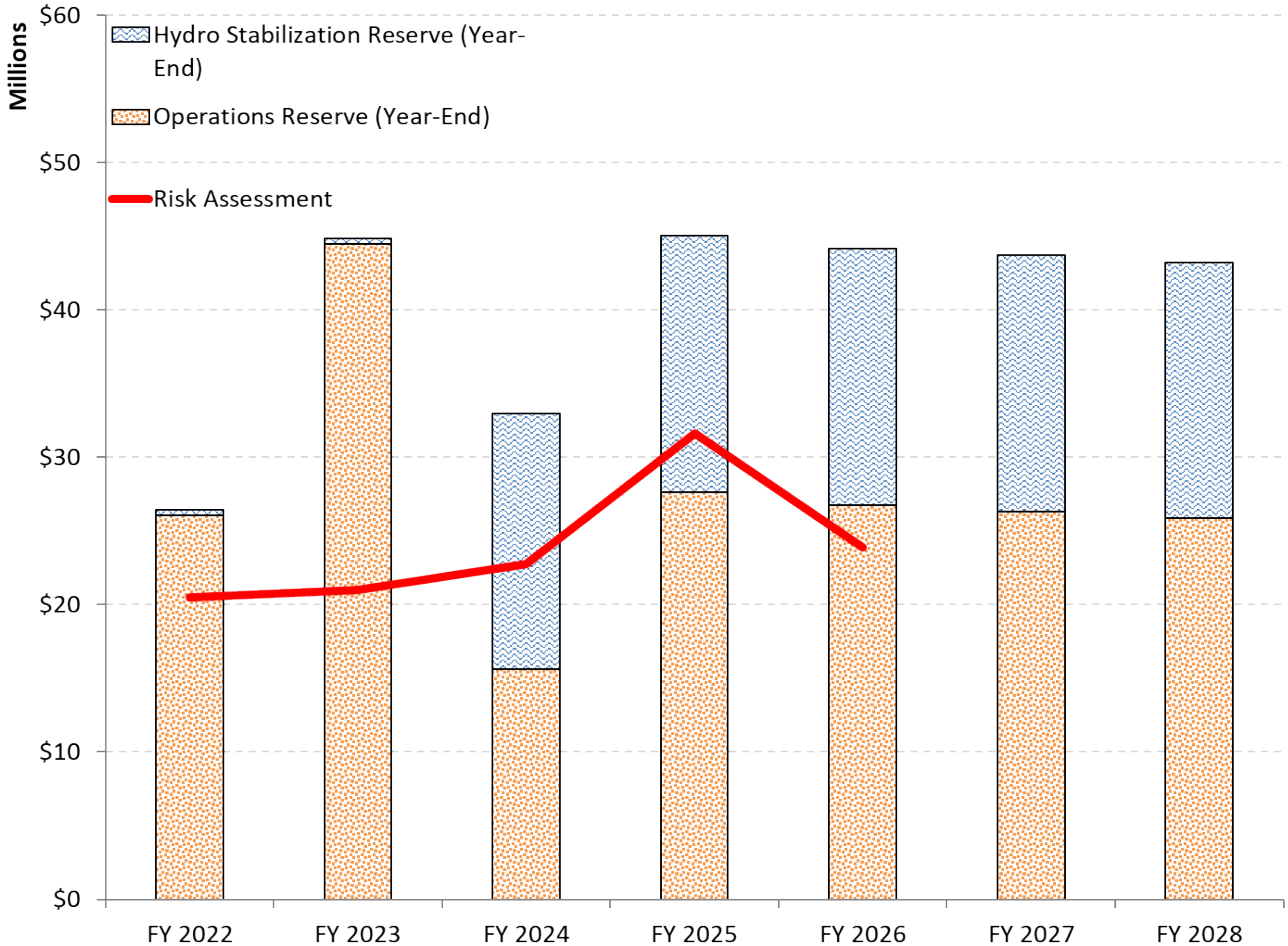


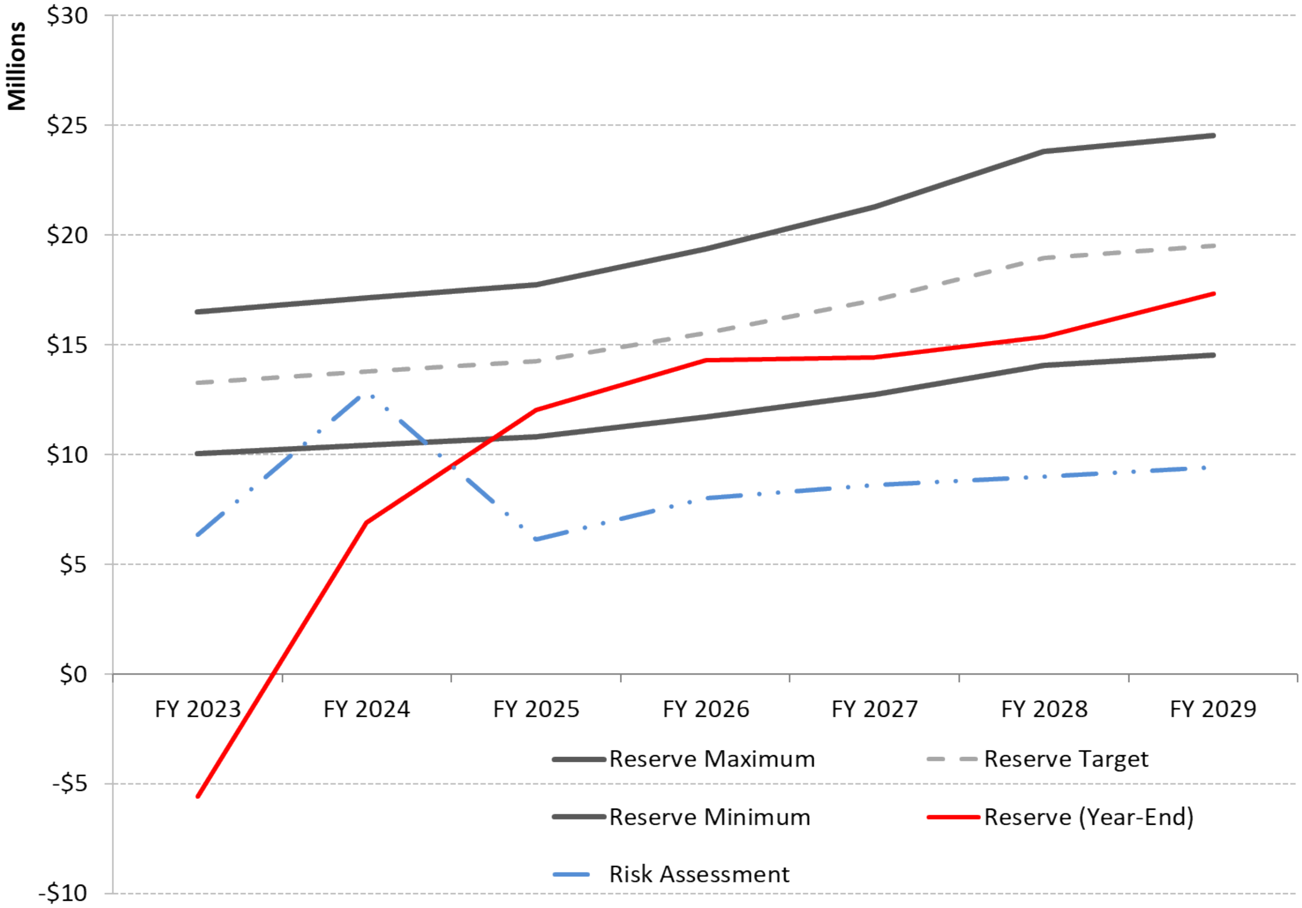
Table 13 summarizes the risk assessment calculation for the Distribution Operations Reserve through FY 2029. As shown in Figure 13, the Distribution Operations Reserve is also projected to drop near to the minimum reserve guidelines in FY 2025, but is projected to recover to target levels over the course of the forecast period. The risk assessment includes the revenue shortfall that could accrue due to:

1. Lower than forecasted sales revenue; and
2. An increase of 10% of planned system improvement CIP expenditures for the budget year.

Table 13: Electric Distribution Fund Risk Assessment ($000)

	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
Total non-commodity revenue	$77,592	$82,369	$90,316	$98,135	$102,722
Max. revenue variance, previous ten years	8%	8%	8%	8%	8%
Risk of revenue loss	$6,124	$6,501	$7,128	$7,745	$8,107
CIP Budget	$0	$15,143	$14,671	$12,688	$13,089
CIP Contingency @10%	$0	$1,514	$1,467	$1,269	$1,309
Total Risk Assessment value	$6,124	$8,015	$8,595	$9,014	$9,416

Figure 13: Electric Distribution Operations Reserve Adequacy

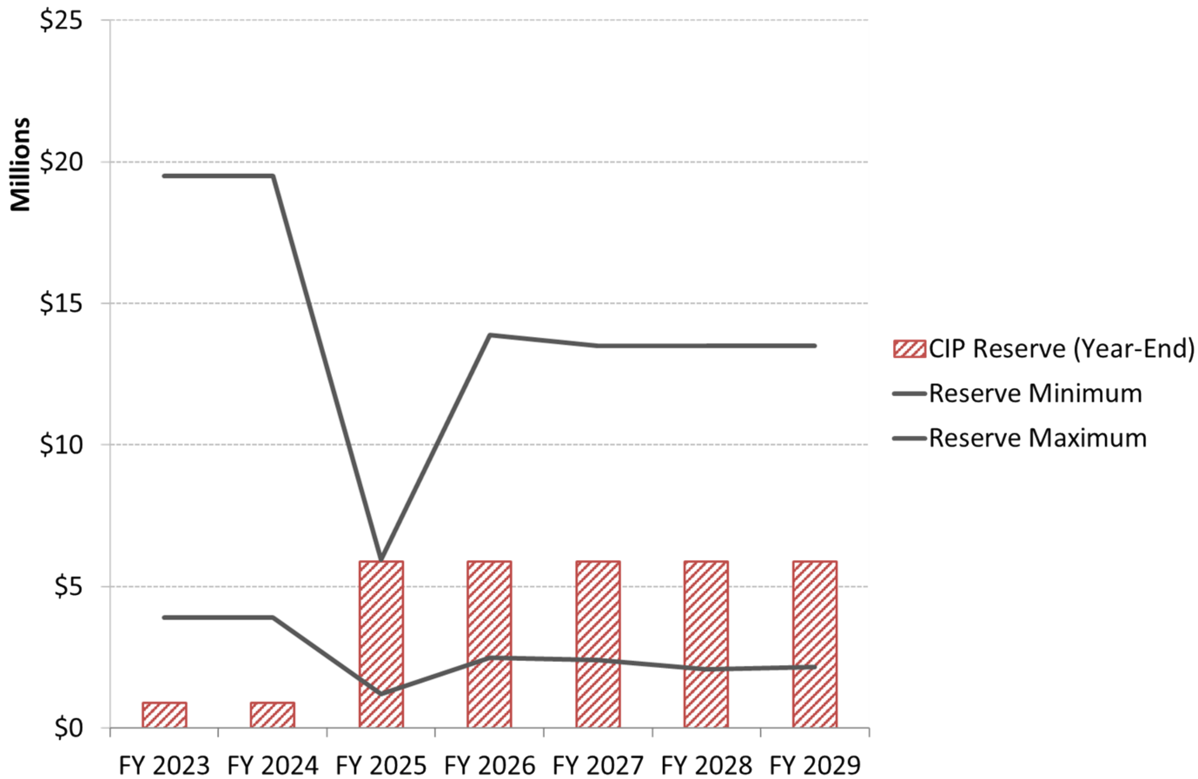


The Electric Utility also has a CIP Reserve that acts as a reserve for short term capital contingencies or as a place to set aside funds for large, one-time projects that the Utilities would otherwise need to debt-fund. Figure 14 below reflects the maximum and minimum CIP Reserve guideline levels, starting in FY 2023. Because of the fluctuating annual dollar amounts and timing of CIP projects budgeted to occur during the forecast period, as well as the potential for new ongoing projects to be included in the CIP plan in later years, four years of budgeted CIP are used to calculate the reserve maximum levels. The minimum CIP Reserve level is 20% of the maximum CIP Reserve guideline level.

This Financial Plan plans to fund the CIP Reserve to its minimum level by the end of FY 2025 and includes additional contributions to the reserve in later years. In addition, staff recommends amending the reserve guidelines to direct staff to transfer any unspent CIP budget that is not reappropriated or encumbered at the end of each fiscal year to the CIP Reserve. These represent ratepayer funds already collected for the purpose of CIP investment, and retaining them in the CIP Reserve would allow the City to use them to fund future unanticipated CIP expenses (such as mid-year budget adjustments due to increased costs for specific projects) that were not included in a financial plan.

Figure 14 shows the projected CIP Reserve balances and guideline levels for FY 2023 through FY 2029. The CIP reserve is projected to be above the minimum guideline by the end of FY 2025. Per the Reserves Management Practices (Appendix B), Section 10, any rate plan that does not return CIP reserves to minimum levels within one year requires Council approval. Council approved the FY 2024 Electric Utility Financial Plan, which included keeping the CIP Reserve below minimum until FY 2026. This plan achieves minimum CIP Reserve levels by the end of FY 2025.

Figure 14: Electric CIP Reserve Adequacy



SECTION 5G: LONG-TERM OUTLOOK

This forecast covers the period from FY 2025 through FY 2029, but various long-term developments may create new costs for the utility over the next 10 to 35 years. While it is challenging to accurately forecast the impact these events will have on the utility's costs, it is worth noting them as future milestones and keeping them in mind for long-term planning purposes.

For the supply portfolio, the 2020s are seeing a number of notable events. The contract with the Western Area Power Administration (Western) for power from the Central Valley Project (CVP) is expiring in 2024, with an option in 2024 to reduce the City's share. Determining the future relationship with Western after 2024 will be important in the years leading up to the contract expiration, especially because this resource represents nearly 40% of the electric portfolio and is the utility's largest source of carbon-free electricity.

Over the next decade six of the utility's renewable contracts will begin expiring with the first contract expired in 2026 and the last in 2034. It is difficult to know whether renewable energy prices will be more or less favorable than the contract prices when those contracts expire.

The costs of the Calaveras hydroelectric project is changing in the 2020s, with debt service costs dropping by half or approximately $4 million in 2025 as some of the debt is paid off, and all debt will be retired by the end of 2032. Some additional debt may be issued to fund the costs of relicensing the project, but this is not anticipated to be as high as the current debt service. The project will only be 40 years old at that time, and hydroelectric projects can last for 70-100 years before major rebuilding is needed. Calaveras debt service represents roughly 70% of the annual costs of that project (and nearly 7% of the utility's total costs), so when the debt is retired, the project could be a low-cost asset for the utility, providing carbon-free energy equal to around 13% of the Electric Utility's supply needs in an average year.

Another factor that may affect the utility's supply costs in the long run is carbon allowance revenue. Currently the Electric Utility receives $3 to $5 million per year in revenue from allocated carbon allowances under the State's cap-and-trade program. It uses that revenue to pay for energy efficiency programs and to purchase renewable energy to support the utility's Carbon Neutral Plan. Staff expects that revenue source to continue in some fashion through 2030, although the number of allowances allocated to Palo Alto have been reduced. Discussions at the state level are ongoing to determine any further restrictions CARB may wish to enact on both the number of future allowances received as well as usage of allocation sales revenues. If the Electric Utility no longer received these allowances or was limited in how it could spend revenues, it would have to fund these programs from sales revenues.

Transmission costs are also continuing to rise. If the State continues to increase mandates or incentives for renewable energy development, integrating these new projects into the transmission grid will be an ever-increasing challenge, some costs of which will be borne by Palo Alto. The planned expansion of the CAISO to a larger regional grid control area may result in additional transmission costs that could further increase CPAU's transmission costs. In addition to the costs of new transmission lines that will need to be built, flexible resources will be required to balance rapid changes in wind or solar output throughout the day. Palo Alto will likely bear some of the costs of these new lines and resources. CPAU is also currently investigating installing a second transmission interconnection for Palo Alto, which could be funded by the Electric Special Projects Reserve.

Over the next several years the Electric Utility will continue to execute its usual monitoring, repair, and replacement routine for the distribution system, but is also beginning the rollout of various smart grid technologies and a major grid modernization effort that will result in rebuilding of the electric system and capacity increases. This rebuild will involve debt service that will be repaid over 30 years and will have an uncertain effect on electric system capital investment needs in the 2030s and beyond.

The utility is actively promoting electric vehicle ownership and gas-to-electric fuel switching in Palo Alto. In the coming years these factors are expected to create notable increases in electric consumption and have a variety of impacts on the distribution system. Other technologies such as battery storage and rooftop solar installations are also becoming even more common. The utility has already started to take some of these factors into account in its long-term planning processes but will need to continue to incorporate them into its planning methodologies.

Over the long term, electricity may replace natural gas and petroleum almost entirely as part of the City's efforts to combat climate change. Many, if not most, vehicles would use electricity, though hydrogen is another potential fuel source under development and other technologies might be developed. Staff is undertaking initial analysis of these types of scenarios in the context of the Sustainability and Climate Action Plan (S/CAP) development process. Utility analyses in progress or completed that take into account potential load growth benefits and impacts include a grid modernization study, the Electric Integrated Resource Plan, and an upcoming S/CAP funding needs and sources study that may help assess the impact of these trends on rates. Staff will integrate results from these studies in Financial Plans as they become available.

SECTION 5H: ALTERNATIVE RATE PROJECTIONS

Staff is not presenting any alternative rate projections in this Financial Plan.

SECTION 6: DETAILS AND ASSUMPTIONS

SECTION 6A: ELECTRICITY PURCHASES

As shown in Figure 16 the utility is projected to get roughly 45% of its energy from hydroelectric projects in a normal year, but is getting over 50% during FY 2024 and FY 2025 due to the favorable hydroelectric generation conditions resulting from the rains of the 2022/2023 winter. In the longer term contracts with renewable sources make up approximately 50% to 55% of the portfolio. If hydroelectric conditions end up being lower than forecasted (as they were in FY 2023) or if loads increase, some power may come from unspecified market sources. Under the City's Carbon Neutral Plan, CPAU purchases RECs corresponding to the amount of market energy it purchases.

Figure 16: Electricity Supply by Source

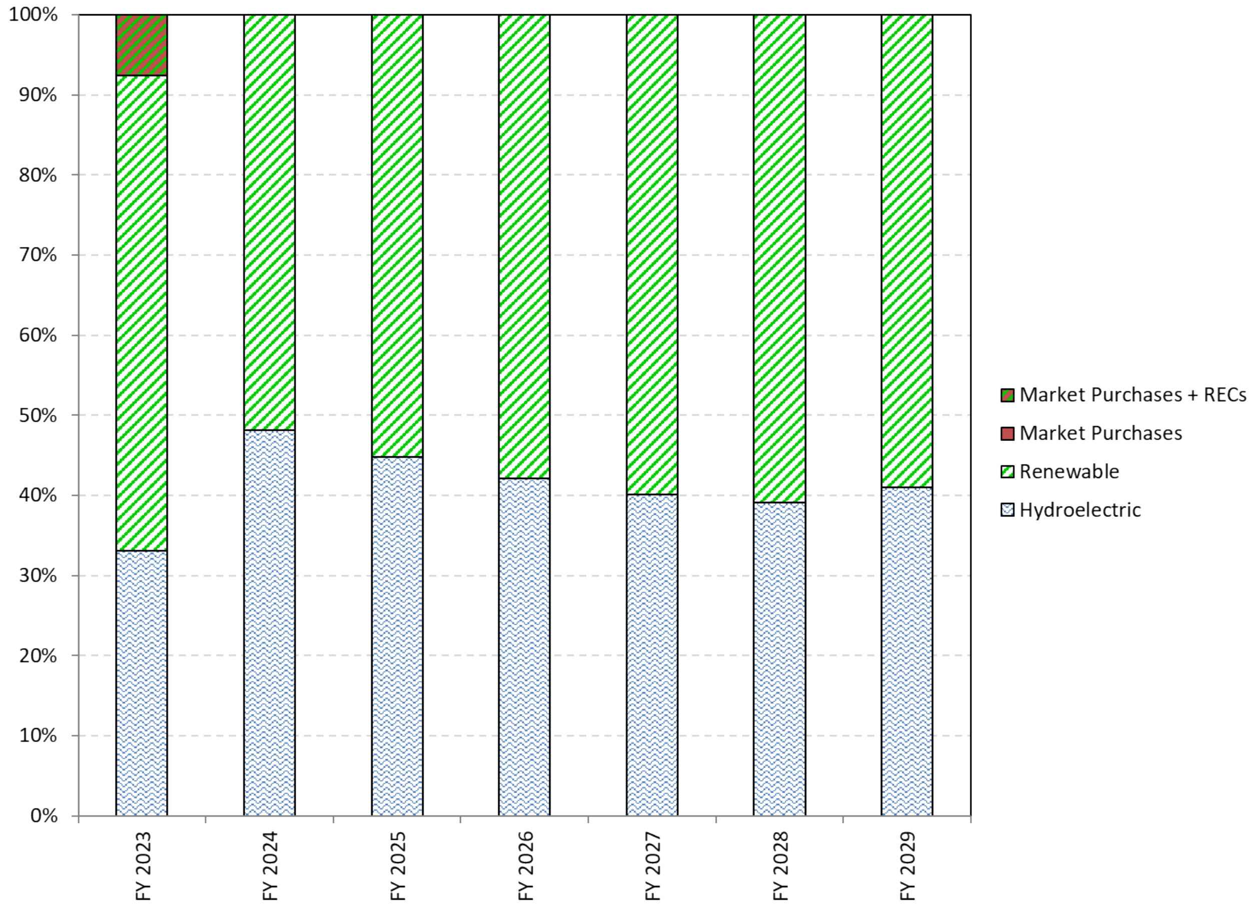
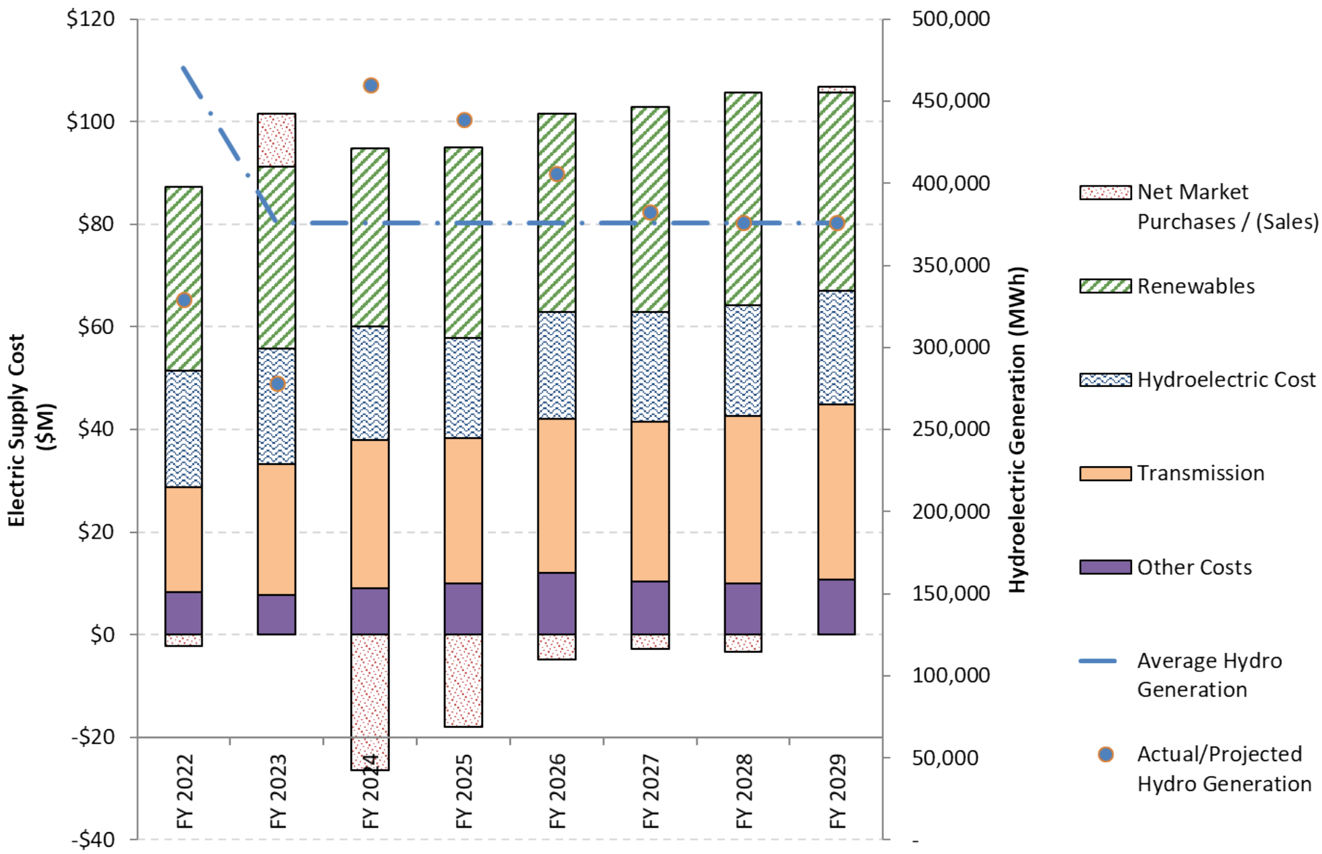


Figure 16 shows the historical and projected costs for the electric supply portfolio,[11] as well as average and actual hydroelectric generation.[12] FY 2022 and FY 2023 had lower than average hydroelectric generation, while FY2024 and FY 2025 had higher than forecasted generation. Starting in FY 2023 (in the FY 2024 Electric Utility Financial Plan) staff lowered its projection of an average hydroelectric year to more closely align with the past 10 years of historical averages. But with the current favorable reservoir conditions staff is projecting hydroelectric generation to be better than average through FY 2026.

Renewable energy costs have stayed relatively flat as one renewable energy contract ended while another renewable project came online to fulfill the City's carbon neutral and RPS goals. The current market outlook is uncertain for newer renewables projects because of headwinds from supply chain issues and tailwinds from federal subsidies. Transmission charges are projected to increase as new transmission lines are built throughout California to accommodate new renewable projects. In total, net electric supply costs are projected to increase from about average of $83 million from FY 2022 through FY 2025 to about $106 million by FY 2029.

[11] Costs are shown net of wholesale revenues and cannot be directly compared with the electric supply purchase figures shown in Appendix A: Electric Utility Financial Forecast Detail.
[12] Average hydroelectric generation based on the current E-HRA rate schedule.

Figure 17: Electric Supply Portfolio Costs, Historical and Projected



SECTION 6B: OPERATIONS

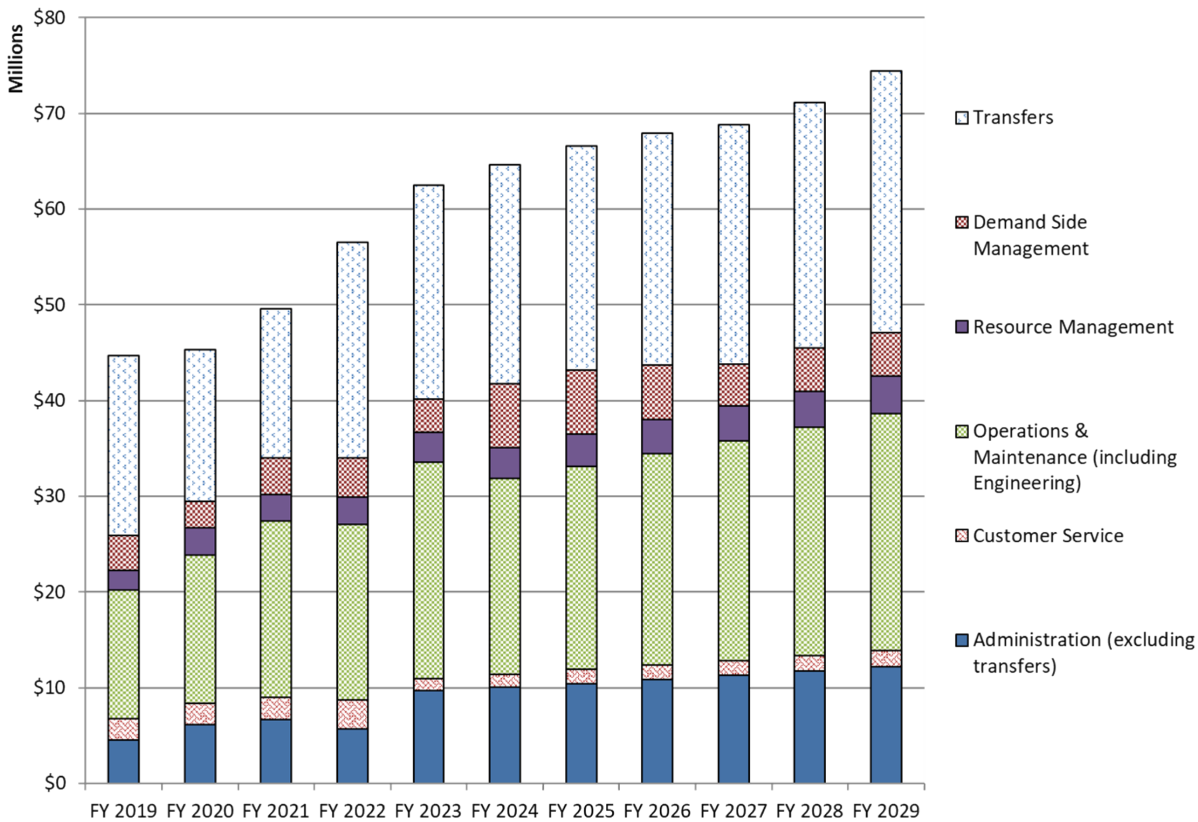
CPAU's Electric Utility operations include the following activities:

- Administration, including financial management of charges allocated to the Electric Utility for administrative services provided by the General Fund and for Utilities Department administration, as well as debt service and other transfers. Additional detail on Electric Utility debt service is provided in Section 6D (Debt Service)
- Customer Service
- Engineering work for maintenance activities (as opposed to capital activities)
- Operations and Maintenance of the distribution system; and
- Resource Management

Appendix C: Description of Electric Utility Operational Activities includes detailed descriptions of the work associated with each of these activities.

From FY 2019 to FY 2023, overall operations costs have risen annually by about 7% on average. This is primarily driven by increased operations and maintenance and administrative overhead allocations. Operations and maintenance costs are increasing primarily due to inflation driven by the tight labor market and the cost of using contract field crews to backfill for vacant positions. These costs may be reduced depending on how much work is needed and may be phased out as longer-term employees are gained.

Figure 18: Historical and Projected Electric Utility Operational Costs



SECTION 6C: CAPITAL IMPROVEMENT PROGRAM (CIP)

Staff projects CIP spending for FY 2025 through FY 2029 to focus primarily on grid modernization. Other significant one-time projects include a rebuild of Hanover Substation (budgeted in FY 2024, mid-year), a major project at the Colorado Substation, undergrounding of power lines in the Foothills, and completion of the Smart Grid (Advanced Metering Infrastructure) project. Ongoing projects include replacement of deteriorated wood poles, substation physical security upgrades, and ongoing capital investment in smaller projects on the electric distribution system to maintain/improve reliability. Total spending over the forecast period, including the FY 2024 budget, is over $450 million, far higher than past CIP spending plans. Of this, about $330 million is planned to be financed through debt, as explained in *Section 6D: Debt Service* below.

The remainder of the CIP plan for is primarily funded by utility rates, but other sources of funds include connection fees (for Customer Connections), phone and cable companies (primarily for undergrounding), and other funds (such as funds from the Electric Special Projects Reserve for smart grid). The details of the CIP budget will be available in the Proposed FY 2025 Utilities Capital Budget. Table 14 shows the FY 2025 projected budget and the five year CIP spending plan, although these figures are preliminary pending budget discussions starting in May.

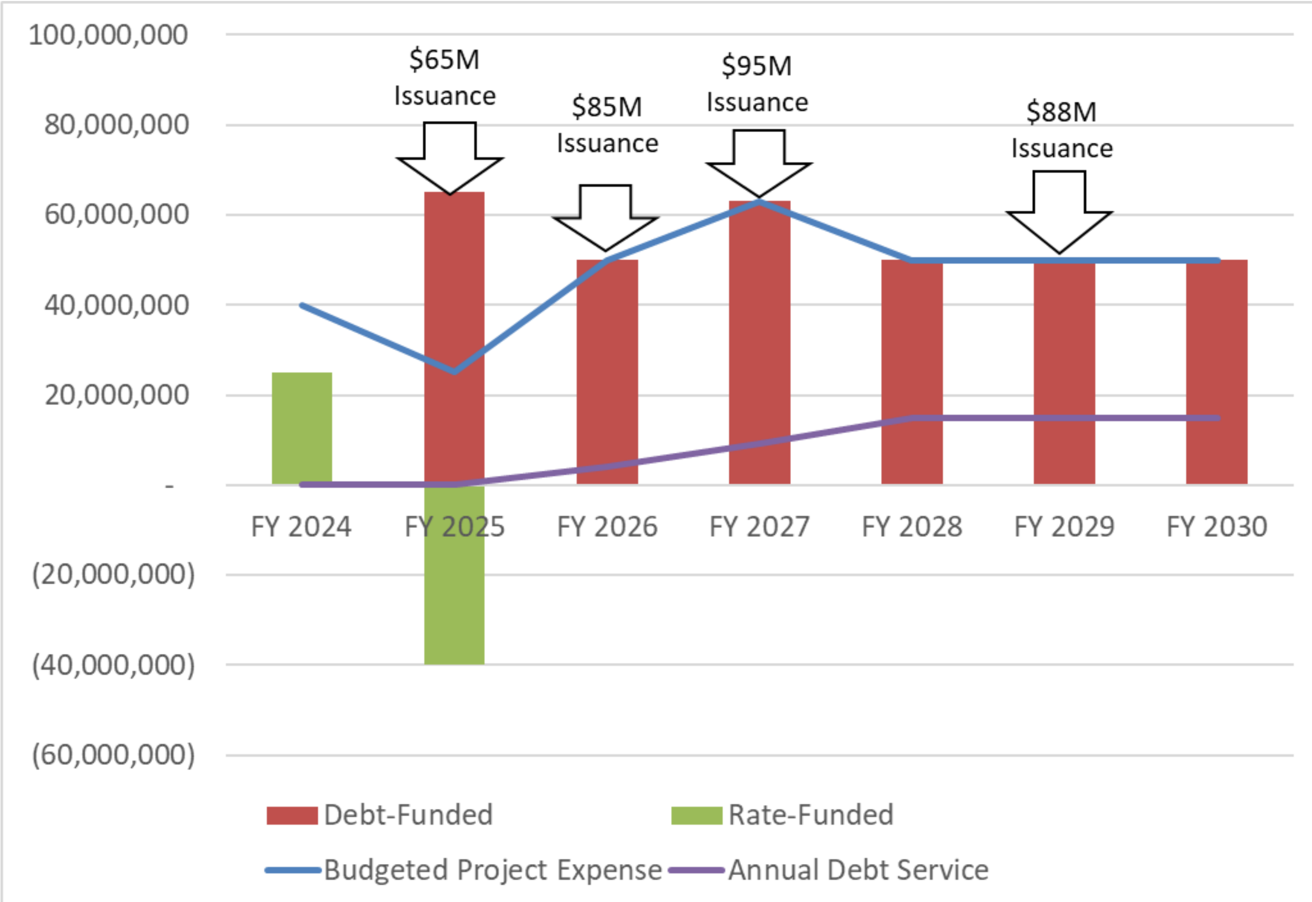
Table 14: Electric Utility CIP Spending ($000)

Project Category	Current Budget *	FY 2025 (New Budget, Excluding Reappropriations)	FY 2026	FY 2027	FY 2028	FY 2029
One Time Projects	26,363,974	10,100,000	3,750,000	2,850,000	750,000	750,000
Reliability	4,516,765	765,000	798,300	900,000	529,000	544,870
Undergrounding	1,368	-	-	-	-	-
4/12 kV Conversion	2,487,541	-	-	-	-	-
Underground Rebuild	1,112,000	-	-	-	-	-
Ongoing	8,093,369	3,915,000	3,875,000	4,040,500	4,361,000	4,491,830
Customer Connections	5,865,828	2,700,000	2,700,000	2,700,000	2,700,000	2,781,000
Smart Grid	12,710,117	-	-	-	-	-
Grid Modernization	25,000,000	25,000,000	50,000,000	50,000,000	50,000,000	50,000,000
Total	**86,150,963**	**42,480,000**	**61,123,300**	**60,490,500**	**58,340,000**	**58,567,700**
** Includes unspent funds from previous years carried forward or reappropriated to the current fiscal year*						

SECTION 6D: DEBT SERVICE

The Electric Utility made its last payment on the 2007 Electric Utility Clean Renewable Energy Tax Credit Bonds, Series A in FY 2021. This $1.5 million bond issuance was to fund a portion of the construction costs of solar demonstration projects at the Municipal Services Center, Baylands Interpretive Center, and Cubberley Community Center. It currently has no debt service expenses related to its own distribution system (though it does have debt service expenses related to the Calaveras Dam, a power supply expense). However, staff expects to issue substantial amounts of debt to fund up to $300 million in grid modernization expenses through FY 2030. A tentative projection of how much of the cost of that project will be debt funded vs. rate funded is shown in Figure 19 below. This plan is reflected in the financial projections in this Financial Plan. The timing and amount of the debt issuances will likely change as the grid modernization project progresses. Note that the debt issuance in FY 2025 will be used for FY 2024 expenses, resulting in the use of rate/reserve funding in FY 2024 and a refund to the reserves in FY 2025 as the bond proceeds are applied to those FY 2024 expenses.

Figure 19: Projected Funding Plan for Grid Modernization Project



The Electric Utility pledges reserves and net revenue as security for the bond issuances listed in Table 15 even though the Electric Utility is not responsible for the debt service payments. The Electric Utility's reserves or net revenues would only be called upon if the responsible utilities are unable to make their debt service payments. Staff does not currently foresee this occurring. Staff projects that the Electric Utility's net revenues in each future year will exceed 125% of debt service (see Appendix B, line 70).

Table 15: Other Issuances Secured by Electric Utility's Revenues or Reserves

Bond Issuance	Responsible Utilities	Annual Debt Service ($000)	Secured by Electric Utility's:	
			Net Revenues	Reserves
1999 Utility Revenue Bonds, Series A	Storm Drain Wastewater Collection Wastewater Treatment	$1,207	No	Yes
2009 Water Revenue Bonds (Build America Bonds)	Water	$1,977*	No	Yes
2011 Utility Revenue Refunding Bonds, Series A	Gas Water	$1,457	No	Yes
**Net of Federal interest subsidy*				

SECTION 6E: EQUITY TRANSFER

The City calculates the equity transfer from its Electric Utility based on a methodology adopted by Council in 2009, which has remained unchanged since then.[13] Each year it is calculated according to the 2009 Council-adopted methodology and does not require additional Council action.

SECTION 6F: WHOLESALE REVENUES AND OTHER REVENUES

The Electric Utility receives most of its revenues from sales of electricity, but about 20 to 25% comes from other sources. Of these other sources, about 50% to 75% represents wholesale revenues of surplus energy sales. These revenues may offset electric supply purchase costs, smooth rate increases, or fund reserves or other costs. Of the remaining revenues, the largest revenue sources are interest on reserves, connection fees for new or replacement electric services, and carbon allowance revenues associated with the State's cap-and-trade program

Revenues from connection fees have increased since FY 2009 but vary from year to year. Connection fee revenues are collected to offset costs incurred in setting up new connections and are pass-through in nature. Staff forecasts $1.4 million in FY 2025.

Staff projects carbon allowance and interest income revenues to stay relatively stable through the forecast period. However, both of these revenue sources are subject to some uncertainty. This forecast assumes the program State's cap-and-trade program will remain in place but with declining returns through 2030. It is possible this funding source may be removed entirely in the future, as the current CARB plan in the gas fund is for free allowances to stop entirely by 2030.

The forecast for interest income assumes current interest rates continue and there are no major reserve reductions aside from what is anticipated in this Financial Plan. If interest rates rise, interest income could increase, and if reserves decrease (due to drought or a withdrawal from the ESP reserve for a major project), interest income would decrease.

SECTION 6G: SALES REVENUES

The load forecast in *Section 5A: Load Forecast* and the projected rate changes shown in Figure 7 provide the basis for sales revenue projections. As discussed in Section 5A, sales revenues for this utility have been decreasing due to load reduction but are helped by the mild climate in Palo Alto. Palo Alto is a built-out City, so the opportunities for increased load growth are limited to the existing footprint of commercial structures and incremental growth in population. As utilization of existing spaces changes, and energy efficiency measures continue, Palo Alto could see greater load loss. Increased loads from electric vehicles and the electrification of households may increase loads somewhat.

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[13] For more detail on the ordinance adopting the 2009 transfer methodology, see CMR 280:09, Budget Adoption Ordinance for Fiscal Years 2009 and 2010; and CMR 260:09, Finance Committee Report explaining proposed changes to equity transfer methodology.

SECTION 7: COMMUNICATIONS PLAN

The fiscal year (FY) 2025 electric utility communications strategy covers these primary areas: cost drivers, cost containment measures, efficiency services and utility bill savings, capital improvement projects for infrastructure safety and reliability, carbon neutral portfolio, and beneficial electrification. City of Palo Alto Utilities (CPAU) communication methods include utilities webpages, utility bill inserts, messaging on utility bills, email newsletters, print and digital ads, social media, and business and neighborhood customer presentations.

In advance of the rate-setting process, staff working on rates and communications are focusing on informing customers of the need to recover funds to bring financial reserves above the minimum guideline following the 2020 through 2022 reserve drawdowns. It is also important to educate customers about the cost to buy and transport electricity to Palo Alto, as well as the cost to distribute it within Palo Alto, including maintaining and replacing infrastructure, customer service, billing, and administration. Long-term cost trends show supply and distribution costs increasing over time. CPAU implements cost containment as a priority and is improving efficiencies with metering and billing through Advanced Metering Infrastructure (AMI), and a new power Outage Management System (OMS) that automates customer notifications, allowing staff to devote time to restoring service. Despite raising rates, electric costs to customers still remain lower than the comparator regional investor-owned utility, PG&E.

CPAU promotes energy efficiency programs to help customers keep utility bill costs low even as market prices increase or CPAU raises utility rates. Programs such as the Home Efficiency Genie and commercial energy efficiency audits help residents and businesses better understand energy usage, and activities they can implement to improve efficiency and keep utility costs low. The Home Efficiency Genie program now provides a home electrification readiness assessment so customers who want to switch out gas for electric appliances or install an electric vehicle (EV) charger can understand what may be necessary for electric panel upgrades. The City offers attractive financing and assistance with installation to eliminate barriers to adoption.

The Business Energy Advisor (BEA) provides a “concierge” service for businesses to evaluate areas of their facility for efficiency improvements such as in the areas of building envelope, lighting, and heating. BEA acts as the flagship program for businesses to then learn about available rebates for appliance or facility upgrades and opportunities for building electrification. CPAU also offers programs to help non-residential facilities install EV charging infrastructure to assist employees and tenants with goals to switch from fossil fueled transportation to clean, electric driving.

CPAU customers benefit from local control and policy setting, and community values-driven programs and services, including the decision to go carbon neutral in 2013. Palo Alto’s renewable energy purchase agreements contribute to our utility’s long-term energy security and commitment to sustainability. CPAU will highlight these environmental attributes and value in our communications.

APPENDICES

Appendix A: Electric Utility Financial Forecast Detail
Appendix B: Electric Utility Reserves Management Practices
Appendix C: Description of Electric utility Operational Activities
Appendix D: Samples of Recent Electric Utility Outreach Communications

APPENDIX A: ELECTRIC UTILITY FINANCIAL FORECAST DETAIL

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1	FISCAL YEAR	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
2												
3	**STARTING RESERVES**											
4	Reappropriations (Non-CIP)	-	-	-	56,811	120,000	253,000	253,000	253,000	253,000	253,000	253,000
5	Commitments (Non-CIP)	3,725,000	3,910,695	3,518,525	3,512,355	(2,321,000)	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307
6	Low Carbon Fuel Standard (LCFS) Reser	-	-	6,340,000	6,943,525	7,235,894	6,712,544	4,053,126	1,485,979	-	-	-
7	Cap and Trade Program				1,189,000	1,189,000	2,230,759	3,230,759	4,940,759	6,150,759	7,230,759	8,140,759
8	Underground Loan Reserve	730,147	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659
9	Public Benefits Reserves	681,330	809,700	1,904,547	3,027,599	3,890,872	5,672,542	7,431,387	9,033,068	10,568,541	12,031,587	13,421,659
10	Electric Special Projects Reserve	41,837,855	41,664,855	46,664,855	46,664,855	24,649,000	20,148,855	148,855	30,148,855	32,148,855	34,148,855	36,148,855
11	Hydro Stabilization Reserve	11,400,000	11,400,000	15,400,000	15,400,000	400,000	400,000	17,400,000	17,400,000	17,400,000	17,400,000	17,400,000
12	Capital Reserves	879,964	879,964	5,879,964	879,964	879,964	879,964	879,964	5,879,964	5,879,964	5,879,964	5,879,964
13	Rate Stabilization Reserves	9,010,840	-	-	-	-	-	-	-	-	-	-
14	Electrification Reserve						4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000
14	Operations Reserves (Supply & Dist)	18,600,000	45,244,167	38,538,459	29,902,850	28,559,158	38,881,723	22,522,316	39,671,926	41,073,721	40,765,805	41,216,341
15	Unassigned	244,354	-	0	(0)	-	-	-	-	-	-	-
16	TOTAL STARTING RESERVES	87,109,490	104,636,040	118,973,010	108,303,618	65,329,547	89,806,353	70,546,373	123,440,517	128,101,807	132,336,936	137,087,544
17												
18	**REVENUES**											
19	Net Sales	131,471,245	137,026,504	129,389,001	130,557,545	164,554,954	172,499,236	169,251,184	177,609,240	185,889,795	194,655,810	203,790,614
20	Wholesale Revenues	21,060,071	20,686,925	25,959,207	25,529,188	30,745,937	46,036,151	44,045,073	30,470,737	28,761,527	28,880,651	25,773,090
21	Other Revenues and Transfers In	19,914,635	15,260,937	9,324,996	9,348,837	32,788,973	7,487,037	7,918,630	10,102,079	10,322,293	10,432,345	10,530,882
22	TOTAL REVENUES	172,445,951	172,974,366	164,673,204	165,435,570	228,089,864	226,022,424	221,214,887	218,182,056	224,973,615	233,968,806	240,094,586
23												
24	**EXPENSES**											
25	Electric Supply Purchases	97,989,910	97,716,399	106,202,833	120,493,205	128,512,096	114,427,008	121,078,734	127,167,371	128,726,357	131,243,066	132,597,189
26	Operating Expenses											
27	Administration											
28	*Allocated Charges*	*4,568,027*	*6,146,498*	*6,674,515*	*5,732,098*	*9,664,335*	*10,050,709*	*10,452,918*	*10,871,097*	*11,305,551*	*11,757,503*	*12,227,733*
29	*Rent*	*5,454,097*	*5,666,805*	*5,949,976*	*6,069,000*	*6,324,000*	*6,474,174*	*6,733,141*	*7,002,466*	*7,282,565*	*7,573,867*	*7,876,822*
30	*Equity Transfer*	*12,973,000*	*13,134,000*	*13,638,000*	*14,138,000*	*14,534,000*	*14,905,000*	*15,121,000*	*15,550,000*	*15,989,000*	*16,421,000*	*16,892,000*
31	*Transfers and Other Adjustments*	*369,321*	*(3,000,057)*	*(4,027,621)*	*2,311,226*	*1,495,296*	*1,474,594*	*1,533,578*	*1,594,921*	*1,658,718*	*1,725,067*	*2,571,441*
32	Subtotal, Administration	23,364,445	21,947,247	22,234,870	28,250,324	32,017,631	32,904,477	33,840,636	35,018,484	36,235,834	37,477,437	39,567,996
33	Resource Management	2,082,405	2,870,524	2,781,010	2,824,303	3,086,893	3,199,728	3,337,316	3,474,146	3,592,267	3,726,330	3,872,887
34	Demand Side Management	3,655,547	2,733,047	3,819,646	4,086,083	3,477,495	6,715,260	6,689,764	5,766,493	4,442,832	4,530,005	4,577,027
35	Operations and Mtc	11,606,585	13,450,568	15,988,315	16,576,083	20,538,544	18,323,978	19,084,973	19,858,105	20,591,664	21,373,323	22,217,356
36	Engineering (Operating)	1,838,799	2,051,303	2,408,524	1,806,550	2,022,434	2,102,495	2,187,351	2,275,108	2,364,474	2,457,918	2,555,940
37	Customer Service	2,180,400	2,228,469	2,320,338	2,974,968	1,328,808	1,378,296	1,436,736	1,495,354	1,547,991	1,604,957	1,667,871
38	Allowance for Unspent Budget	-	-	-	-	-	(653,147)	(680,138)	(707,644)	(734,072)	(762,568)	(792,845)
39	Subtotal, Operating Expenses	44,728,180	45,281,157	49,552,702	56,518,311	62,471,805	63,971,087	65,896,638	67,180,047	68,040,990	70,407,403	73,666,233
40	Capital Expenses											
41	Capital Program Contribution	10,770,456	15,539,840	21,487,061	34,524,744	21,656,368	66,884,310	-	15,143,324	14,671,084	12,687,640	13,089,202
42	Capital-Related Debt Service	100,000	100,000	100,000	100,000	20,789	-	-	4,030,024	9,300,055	14,880,088	14,880,088
43	Subtotal, Capital Expenses	10,870,456	15,639,840	21,587,061	34,624,744	21,677,157	66,884,310	-	19,173,348	23,971,139	27,567,728	27,969,291
44	TOTAL EXPENSES	153,588,546	158,637,396	177,342,596	211,636,260	212,661,058	245,282,404	186,975,372	213,520,766	220,738,486	229,218,198	234,232,712
45												
46	**ENDING RESERVES**											
47	Reappropriations (Non-CIP)	-	-	56,811	120,000	253,000	253,000	253,000	253,000	253,000	253,000	253,000
48	Commitments (Non-CIP)	3,910,695	3,518,525	3,512,355	(2,321,000)	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307	9,400,307
51	Low Carbon Fuel Standard (LCFS) Reser	-	6,340,000	6,943,525	7,235,894	6,712,544	4,053,126	1,485,979	-	-	-	-
52	Cap and Trade Program			1,189,000	1,189,000	2,230,759	3,230,759	4,940,759	6,150,759	7,230,759	8,140,759	8,870,759
53	Underground Loan Reserve	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659	726,659
54	Public Benefits Reserves	809,700	1,904,547	3,027,599	3,890,872	5,672,542	7,431,387	9,033,068	10,568,541	12,031,587	13,421,659	14,733,094
55	Electric Special Projects Reserve	41,664,855	46,664,855	46,664,855	24,649,000	20,148,855	148,855	30,148,855	32,148,855	34,148,855	36,148,855	38,148,855
56	Hydro Stabilization Reserve	11,400,000	15,400,000	15,400,000	400,000	400,000	17,400,000	17,400,000	17,400,000	17,400,000	17,400,000	17,400,000
57	Capital Reserve	879,964	5,879,964	879,964	879,964	879,964	879,964	5,879,964	5,879,964	5,879,964	5,879,964	5,879,964
58	Rate Stabilization Reserve	-	-	-	-	-	-	-	-	-	-	-
59	Electrification Reserve					4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000	4,500,000
60	Operations Reserve (Supply & Dist)	45,244,167	38,538,459	29,902,850	28,559,158	38,881,723	22,522,316	39,671,926	41,073,721	40,765,805	41,216,341	43,036,780
61	Unassigned	-	0	(0)	-	-	-	-	-	-	-	-
62	TOTAL ENDING RESERVES	104,636,040	118,973,010	108,303,618	65,329,547	89,806,353	70,546,373	123,440,517	128,101,807	132,336,936	137,087,544	142,949,418

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FISCAL YEAR	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
ELECTRIC LOAD		**0**	**0**								
Purchases (MWh)	905,071	879,913	827,106	836,828	849,043	869,163	835,686	832,000	825,954	820,400	814,662
Sales (MWh)	884,322	854,761	813,881	812,841	825,297	830,051	810,616	807,040	801,176	795,788	790,222
BILL AND RATE CHANGES											
System Average Rate ($/kWh)	$ 0.1487	$ 0.1603	$ 0.1590	$ 0.1606	$ 0.1994	$ 0.2078	$ 0.2088	$ 0.2201	$ 0.2320	$ 0.2446	$ 0.2579
Change in System Average Rate	5%	8%	-1%	1%	24%	4%	0%	5%	5%	5%	5%
Change in Average Residential Bill	6%	8%	-1%	-1%	5%	21%	0%	5%	5%	5%	5%
REVENUES											
Net Sales	76%	79%	79%	78%	61%	76%	77%	81%	83%	83%	85%
Other Revenues and Transfers In	24%	21%	21%	21%	28%	24%	23%	19%	17%	17%	15%
TOTAL REVENUES	100%	100%	100%	99%	89%	100%	100%	100%	100%	100%	100%
EXPENSES											
Commodity Purchases	53%	53%	53%	55%	58%	39%	55%	51%	51%	50%	50%
Operating Expenses											
Administration											
Allocated Charges	*3%*	*4%*	*4%*	*3%*	*5%*	*4%*	*6%*	*5%*	*5%*	*5%*	*5%*
Rent	*4%*	*4%*	*3%*	*3%*	*3%*	*3%*	*4%*	*3%*	*3%*	*3%*	*3%*
Debt Service	*6%*	*5%*	*4%*	*4%*	*4%*	*4%*	*3%*	*4%*	*6%*	*9%*	*8%*
Equity Transfer	*8%*	*8%*	*8%*	*7%*	*7%*	*6%*	*8%*	*7%*	*7%*	*7%*	*7%*
Transfers and Other Adjustments	*0%*	*-2%*	*-2%*	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*	*1%*
Subtotal, Administration	21%	18%	17%	18%	20%	17%	21%	21%	23%	25%	25%
Resource Management	1%	2%	2%	1%	2%	1%	2%	2%	2%	2%	2%
Operations and Mtc	8%	8%	9%	8%	10%	7%	10%	9%	9%	9%	9%
Engineering (Operating)	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Customer Service	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Allowance for Unspent Budget	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Subtotal, Operating Expenses	32%	31%	31%	30%	33%	27%	34%	33%	35%	37%	38%
Capital Program Contribution	7%	10%	11%	11%	7%	27%	0%	7%	7%	6%	6%
TOTAL EXPENSES	92%	95%	94%	97%	98%	93%	89%	91%	92%	93%	93%
SUPPLY OPERATIONS RESERVE											
Min (60 days of non-capital expenses)	16,831,022	16,957,154	18,345,636	20,817,535	22,301,354	19,923,460	21,062,871	22,110,623	22,412,033	22,874,360	23,148,588
Target (90 days of non-capital expenses)	25,246,533	25,435,732	27,518,453	31,226,303	33,452,031	29,885,189	31,594,307	33,165,935	33,618,049	34,311,540	34,722,882
Max (120 days of non-capital expenses)	33,662,044	33,914,309	36,691,271	41,635,071	44,602,708	39,846,919	42,125,743	44,221,246	44,824,065	45,748,720	46,297,176
DISTRIBUTION OPERATIONS RESERVE											
Min (60 days of non-capital expenses)	7,869,900	8,621,917	8,051,581	7,811,860	10,035,492	10,426,314	10,800,438	11,701,048	12,741,650	14,084,430	14,525,802
Target (90 days of non-capital expenses)	10,096,233	11,071,856	10,898,913	10,608,212	13,266,354	13,781,173	14,267,972	15,541,561	17,022,183	18,952,824	19,527,952
Max (120 days of non-capital expenses)	12,322,566	13,521,795	13,746,245	13,404,564	16,497,217	17,136,033	17,735,506	19,382,073	21,302,716	23,821,219	24,530,102
Risk Assessment Value	4,992,321	6,001,771	6,381,125	6,668,204	6,330,333	12,894,566	6,123,942	8,015,246	8,595,304	9,014,046	9,416,218
DEBT SERVICE COVERAGE RATIO											
Net Revenues (125% of Debt Service)	451%	518%	214%	-43%	535%	649%	818%	371%	300%	264%	272%
Available Reserves (5x Debt Service)*	11.9	16.1	13.4	8.4	9.4	7.0	23.9	13.5	8.7	6.5	6.8

**For the purposes of debt covenants, the unrestricted reserves of other utilities may be counted toward available reserves for this measure. A ratio below 5x means that this utility is relying on reserves of other utilities to meet debt covenants.*

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APPENDIX B: ELECTRIC UTILITY RESERVES MANAGEMENT PRACTICES

The following reserves management practices are used when developing the Electric Utility Financial Plan:

Section 1. Definitions

a) "Financial Planning Period" – The Financial Planning Period is the range of future fiscal years covered by the Financial Plan. For example, if the Financial Plan delivered in conjunction with the FY 2015 budget includes projections for FY 2015 to FY 2019, FY 2015 to FY 2019 would be the Financial Planning Period.
b) "Fund Balance" – As used in these Reserves Management Practices, Fund Balance refers to the Utility's Unrestricted Net Assets.
c) "Net Assets" - The Government Accounting Standards Board defines a Utility's Net Assets as the difference between its assets and liabilities.
d) "Unrestricted Net Assets" - The portion of the Utility's Net Assets not invested in capital assets (net of related debt) or restricted for debt service or other restricted purposes.

Section 2. Supply Fund Reserves

The Electric Supply Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 4 (Reserve for Commitments)
b) For operating budgets reappropriated from previous years, as described in Section 5 (Reserve for Reappropriations)
c) For special projects for the benefit of the Electric Utility ratepayers, as described in Section 6 (Electric Special Projects Reserve)
d) For year to year balancing of costs associated with the Electric Utility's hydroelectric resources, as described in Section 7 (Hydroelectric Stabilization Reserve)
e) For rate stabilization, as described in Section 11 (Rate Stabilization Reserves)
f) For operating contingencies, as described in Section 12 (Operations Reserves)
g) For tracking unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the electric utility under the State's Cap and Trade Program, as described in Section 16 (Cap and Trade Program Reserve)
h) For tracking funding of City buildings, appliance and vehicle electrification projects and programs, as described in Section 17 (Electrification Reserve)
i) Any funds not included in the other reserves will be considered Unassigned Reserves and shall be returned to ratepayers or assigned a specific purpose as described in Section 13 (Unassigned Reserves).

Section 3. Distribution Fund Reserves

The Electric Distribution Fund Balance is reserved for the following purposes:

a) For existing contracts, as described in Section 4 (Reserves for Commitments)
b) For operating and capital budgets reappropriated from previous years, as described in Section 5 (Reserves for Reappropriations)
c) As an offset to underground loan receivables, as described in Section 8 (Underground Loan Reserve)

d) To hold Public Benefit Program funds collected but not yet spent, as described in Section 9 (Public Benefits Reserve)
e) For cash flow management and contingencies related to the Electric Utility's Capital Improvement Program (CIP), as described in Section 10 (CIP Reserve)
f) For rate stabilization, as described in Section 11 (Rate Stabilization Reserves)
g) For operating contingencies, as described in Section 12 (Operations Reserves)
h) For tracking revenues earned via the sale of Low Carbon Fuel Credits allocated by the California Air Resources Board to the City, as well as expenses incurred, in accordance with California's Low Caron Fuel Standard program, as described in Section 15 (Low Carbon Fuel Standard Reserve)
i) Any funds not included in the other reserves will be considered Unassigned Reserves and shall be returned to ratepayers or assigned a specific purpose as described in Section 13 (Unassigned Reserves).

Section 4. Reserves for Commitments

At the end of each fiscal year the Electric Supply Fund and Electric Distribution Fund Reserves for Commitments will be set to an amount equal to the total remaining spending authority for all contracts in force for the Electric Supply Fund and Electric Distribution Fund, respectively, at that time.

Section 5. Reserves for Reappropriations

At the end of each fiscal year the Electric Supply Fund and Electric Distribution Fund Reserves for Reappropriations will be set to an amount equal to the amount of all remaining capital and non-capital budgets that will be reappropriated to the following fiscal year for each Fund in accordance with Palo Alto Municipal Code Section 2.28.090.

Section 6. Electric Special Projects Reserve

The Electric Special Projects Reserve (ESP Reserve) will be managed in accordance with the policies set forth in Resolution 9206 (Resolution of the Council of the City of Palo Alto Approving Renaming the Calaveras Reserve to the Electric Special Project Reserve and Adoption of Electric Special Project Reserve Guidelines). These policies are included from Resolution 9206 as amended to refer to the reserves structure set forth in these Reserves Management Practices:

a) The purpose of the ESP Reserve is to fund projects that benefit electric ratepayers;
b) The ESP Reserve funds must be used for projects of significant impact;
c) Projects proposed for funding must demonstrate a need and value to electric ratepayers. The projects must have verifiable value and must not be speculative, or high-risk in nature;
d) Projects proposed for funding must be substantial in size, requiring funding of at least $1 million;
e) Set a goal to commit funds by the end of FY 2025;
f) Any uncommitted funds remaining at the end of FY 2030 will be transferred to the Electric Supply Operations Reserve and the ESP Reserve will be closed;

Section 7. Hydroelectric Stabilization Reserve

The Hydroelectric Stabilization Reserve is used to manage the supply cost impacts associated with variations in generation from hydroelectric resources. Staff will manage the Hydroelectric Stabilization Reserve as follows:

a) Projected Hydro Output: Near the end of each fiscal year, staff will determine the actual and expected hydro output for that fiscal year, compare that to the long-term average annual output level (495,957 MWh as of March 2018), and multiply the difference by the average of the monthly round-the-clock forward market prices for each month of the current fiscal year.
b) Changes in Reserves. Staff is authorized to transfer the amount described in Sec. 7(a) from the Operations Reserve to the Hydroelectric Stabilization Reserve for hydro output deviations above long-term average levels, or transfer this amount from the Hydroelectric Stabilization Reserve to the Operations Reserve for hydro output deviations below long-term average levels.
c) Implementation of HRA. The level of the Hydroelectric Stabilization Reserve *after* the transfers described above shall be the basis for staff's determination, with Council approval, of whether to implement the Hydro Rate Adjuster (Electric Rate E-HRA) for the following fiscal year.
d) Reserve Guidelines. Staff will manage the Hydroelectric Stabilization Reserve according to the following guideline levels:

Minimum Level	$3 million
Target Level	$19 million
Maximum Level	$35 million

Section 8. Underground Loan Reserve

At the end of each fiscal year, the Underground Loan Reserve will be adjusted by the principal payments made against outstanding underground loans.

Section 9. Public Benefits Reserve

The Public Benefits Reserve will be increased by the amount of unspent Public Benefits Revenues remaining at the end of each fiscal year. Expenditure of these funds requires action by the City Council.

Section 10. CIP Reserve

The CIP Reserve is used to manage cash flow for capital projects and acts as a reserve for capital contingencies. Staff will manage the CIP Reserve according to the following practices:

a) The following guideline levels are set forth for the CIP Reserve. These guideline levels are calculated for each fiscal year of the Financial Planning Period and approved by Council resolution.

Minimum Level	20% of the maximum CIP Reserve guideline level

Maximum Level	Average annual (12 month)[14] CIP budget, for 48 months of budgeted CIP expenses[15]

b) Changes in Reserves: At the end of each fiscal year staff will transfer from the Distribution Operations Reserve to the CIP Reserve an amount equal to the amount of electric utility unspent CIP budget at the end of the fiscal year reduced by the amount of any contractual commitments and reappropriations. Any other additions to or withdrawals from the CIP reserve require Council action.

c) Minimum Level:

   i) If, at the end of any fiscal year, the minimum guideline is not met, staff shall present a plan to the City Council to replenish the reserve. The plan shall be delivered by the end of the following fiscal year, and shall, at a minimum, result in the reserve reaching its minimum level by the end of the next fiscal year. For example, if the CIP Reserve is below its minimum level at the end of FY 2017, staff must present a plan by June 30, 2018 to return the reserve to its minimum level by June 30, 2019. In addition, staff may present, and the Council may adopt, an alternative plan that takes longer than one year to replenish the reserve, or that does so in a shorter period of time.

d) Maximum Level: If there are funds in this reserve in excess of the maximum level staff must propose in the next Financial Plan to transfer these funds to another reserve or return them to ratepayers in the funds to ratepayers, or designate a specific use of funds for CIP investments that will be made by the end of the next Financial Planning period. Staff may also seek City Council to approve holding funds in this reserve in excess of the maximum level if they are held for a specific future purpose related to the CIP.

Section 11. Rate Stabilization Reserves

Funds may be added to the Electric Supply or Distribution Fund's Rate Stabilization Reserves by action of the City Council and held to manage the trajectory of future year rate increases. Withdrawal of funds from either Rate Stabilization Reserve requires action by the City Council. If there are funds in either Rate Stabilization Reserve at the end of any fiscal year, any subsequent Electric Utility Financial Plan must result in the withdrawal of all funds from this Reserve by the end of the Financial Planning Period. The Council may approve exceptions to this requirement, when proposed by staff to provide greater rate stabilization to customers.

Section 12. Operations Reserves

The Electric Supply Fund and Electric Distribution Fund Operations Reserves are used to manage normal variations in the costs of providing electric service and as a reserve for contingencies. Any portion of the Electric Utility's Fund Balance not included in the reserves described in Section 4 to 11 above will be included in the appropriate Operations Reserve unless the reserve has reached its maximum level as set forth in Section 12 (e) below. Staff will manage the Operations Reserves according to the following practices:

a) The following guideline levels are set forth for the Electric Supply Fund Operations Reserve. These guideline levels are calculated for each fiscal year of the Financial Planning Period based on the levels of Operations and Maintenance (O&M) and commodity expense forecasted for that year in the Financial Plan.

Minimum Level	60 days of Supply Fund O&M and commodity expense
Target Level	90 days of Supply Fund O&M and commodity expense
Maximum Level	120 days of Supply Fund O&M and commodity expense

b) The following guideline levels are set forth for the Electric Distribution Fund Operations Reserve. These guideline levels are calculated for each fiscal year of the Financial Planning Period based on the levels of O&M expense forecasted for that year in the Financial Plan.

Minimum Level	60 days of Distribution Fund O&M expense
Target Level	90 days of Distribution Fund O&M expense
Maximum Level	120 days of Distribution Fund O&M expense

c) Minimum Level: If, at the end of any fiscal year, the funds remaining in the Supply Fund or Distribution Fund's Operations Reserve are lower than the minimum level set forth above, staff shall present a plan to the City Council to replenish the reserve. The plan shall be delivered within six months of the end of the fiscal year, and shall, at a minimum, result in the reserve reaching its minimum level by the end of the following fiscal year. For example, if the Operations Reserve is below its minimum level at the end of FY 2014, staff must present a plan by December 31, 2014 to return the reserve to its minimum level by June 30, 2015. In addition, staff may present an alternative plan that takes longer than one year to replenish the reserve.

d) Target Level: If, at the end of any fiscal year, either Operations Reserve is higher or lower than the target level, any Financial Plan created for the Electric Utility shall be designed to return both Operations Reserves to their target levels by the end of the forecast period.

e) Maximum Level: If, at any time, either Operations Reserve reaches its maximum level, no funds may be added to this Reserve. Any further increase in that fund's Fund Balance shall be automatically included in the Unassigned Reserve described in Section 13, below.

Section 13. Unassigned Reserves

If the Operations Reserve in either the Electric Supply Fund or the Electric Distribution Fund reaches its maximum level, any further additions to that fund's Fund Balance will be held in the Unassigned Reserve. If there are any funds in either Unassigned Reserve at the end of any fiscal year, the next Financial Plan presented to the City Council must include a plan to assign them to a specific purpose or return them to the Electric Utility ratepayers by the end of the first fiscal year of the next Financial Planning Period. For example, if there were funds in the Unassigned Reserves at the end of FY 2016, and the next Financial Planning Period is FY 2017 through FY 2021, the Financial Plan shall include a plan to return or assign the funds in the Unassigned Reserve by the end of FY 2017. Staff may present an alternative plan that retains these funds or returns them over a longer period of time.

Section 14. Intra-Utility Transfers between Supply and Distribution Funds

Transfers between Electric Distribution Fund Reserves and Electric Supply Fund Reserves are permitted if consistent with the purposes of the two reserves involved in the transfer. Such transfers require action by the City Council.

Section 15. Low Carbon Fuel Standard (LCFS) Reserve

This reserve tracks revenues earned via the sale of Low Carbon Fuel Credits allocated by the California Air Resources Board to the City, as well as expenses incurred, in accordance with California's Low Caron Fuel Standard program. At the end of each fiscal year, the LCFS Reserve will be adjusted by the net of revenues and expenses associated with California's LCFS program.

Section 16. Cap and Trade Program Reserve

This reserve tracks unspent or unallocated revenues from the sale of carbon allowances freely allocated by the California Air Resources Board to the electric utility, under the State's Cap and Trade Program. Funds in this Reserve are managed in accordance with the City's Policy on the Use of Freely Allocated Allowances under the State's Cap and Trade Program (the Policy), adopted by Council Resolution 9487 in January 2015. At the end of each fiscal year, the Cap and Trade Program Reserve will be adjusted by the net of revenues and expenses associated with the Cap and Trade program.

Section 17. Electrification Reserve

This reserve is used to track funding of City buildings, appliance and vehicle electrification projects and programs, including development and implementation costs and associated financial incentives, loans and rebates for participating customers. The reserve may be funded by any lawful source of funds available for such programs, including new or ongoing utility revenues derived from customer participation. The reserve balance shall be annually adjusted based on the net of revenues and expenses associated with the City's building appliance and vehicle electrification projects and programs using this reserve.

APPENDIX C: DESCRIPTION OF ELECTRIC UTILITY OPERATIONAL ACTIVITIES

This appendix describes the activities associated with the various cost categories referred to in this Financial Plan.

Customer Service: This category includes the Electric Utility's share of the call center, meter reading, collections, and billing support functions. Billing support encompasses staff time associated with bill investigations and quality control on certain aspects of the billing process. It does not include maintenance of the billing system itself, which is included in Administration. This category also includes CPAU's key account representatives, who work with large commercial customers who have more complex requirements for their electric services.

Resource Management: This category includes supply portfolio management, energy procurement, rate setting, and tracking of legislation and regulation related to the electric industry.

Operations and Maintenance: This category includes the costs of a variety of distribution system maintenance activities, including:

- monitoring the substations and performing routine maintenance;
- performing preventative maintenance on the system;
- monitoring the system's status from the UCC using SCADA;
- maintaining the SCADA system;
- investigating outages and other customer complaints and performing emergency repairs;
- clearing vegetation near overhead power lines; and
- testing and replacing meters to ensure accurate sales metering.

Administration: Accounting, purchasing, legal, and other administrative functions provided by the City's General Fund staff, as well as shared communications services, Utilities Department administrative overhead and billing system maintenance costs.

Demand Side Management: Includes the cost of administering energy efficiency programs and the direct cost of rebates paid. Includes solar rebates.

Engineering (Operating): The Electric Utility's engineers focus primarily on the CIP, but a small portion of their time is spent assisting with distribution system maintenance.

PUBLIC SAFETY POWER SHUTOFFS

DON'T FIND YOURSELF UNPREPARED IN THE DARK.

In recent years, wildfires have intensified in California, and utilities are taking action to reduce fire risks related to utility infrastructure. During extreme weather events, a utility may shut off power to electric lines in high threat areas to prevent wildfire. This is called a public safety power shutoff, or PSPS. The City of Palo Alto Utilities (CPAU) has a wildfire mitigation plan that outlines activities by CPAU and other City departments to mitigate the threat of wildfires associated with overhead electric lines and associated equipment.

We have identified the Foothills as an area at elevated risk for wildfire, and want to make sure you are prepared if the unexpected happens.

WHAT YOU CAN EXPECT FROM US:

WILDFIRE PREVENTION
Vegetation management, electric line inspections, prioritized maintenance, tree trimming and inspection to prevent contact with electric lines.

SAFETY INSPECTIONS
If a PSPS is necessary, CPAU will inspect the lines in affected areas after extreme weather has passed before power is safely restored.

EARLY WARNING NOTIFICATION
The City will aim to send customer alerts if anticipating a potential PSPS.

POWER RESTORATION
Power outages could last multiple days depending on weather severity and other factors.

ONGOING UPDATES
Through social media, email, phone call, text, website, and/or other emergency notification systems such as AlertSCC and genasys Protect (Zonehaven).

FUTURE ACTIVITIES
Rebuilding, replacing, rerouting overhead lines and poles; refining construction practices; improving communication systems; coordinating with other utilities.

HOW YOU CAN PREPARE:

- Have a safety plan in place for everyone in the house or building, including pets.
- Plan for any medical needs, such as medications that need to be refrigerated, or devices that require power.
- Build or restock your emergency supply kit, including food, water, flashlights, a radio, fresh batteries, first aid supplies and cash.
- If you own a backup generator, ensure it is ready to safely operate.
- Sign up for AlertSCC at alertscc.org and genasys Protect (Zonehaven) at community.zonehaven.com

CALL BEFORE YOU DIG!

THERE'S MORE THAN JUST DIRT BELOW YOUR YARD.

...nderground utility pipelines can be located anywhere, including under streets, sidewalks and private property—sometimes just inches below the surface. Hitting one of these pipelines while digging, planting or other excavating can cause serious injury, property damage and loss of utility service.

NUMBERS YOU SHOULD KNOW BEFORE YOU DIG:

811
...all Underground Service Alert (USA) at 811. To ...ubmit a single ticket for ...n individual address, visit 811express.com.

48
You must call at least 48 hours before you start your project.

0($)
This is a free service. It is your responsibility to contact USA before digging begins. Failure to contact USA can result in liability for any damage or loss of property.

Dig with care! In the event that a utility service, may it be the following— a GAS LINE, a WATER LINE, or an ELECTRIC LINE, —is disturbed or damaged, call the City of Palo Alto Utilities 24/7 Dispatch ... 2579, or 911 if there is an immediate threat to life or safety. ...tch crews to fix the damaged services and make the area safe.

...OF ...LO ALTO ...ITIES

cityofpaloalto.org/safeutility
Utilities Customer Service (650) 329-2161

ENERGY TIPS

Simple and Substantive Ways to Lower Your Energy Bill.

HOME EFFICIENCY GENIE

If you're looking for ways to lower your energy bill this winter, call the Home Efficiency Genie for a free consultation. Our expert and impartial advisors offer over-the-phone energy and water efficiency advice to help Palo Alto residents save money and stay comfortable. Here are some ways to start saving on your own with help from the Genie.

...ntensified in California, and utilities are taking action to reduce fire ...ture. During extreme weather events, a utility may shut off power to ... to prevent wildfire. This is called a public safety power shutoff, or PSPS. ...AU) has a wildfire mitigation plan that outlines activities by CPAU and ...te the threat of wildfires associated with overhead electric lines and ...re at cityofpaloalto.org/safeutility.

...ou know that metallic foil, or Mylar, balloons are a major cause of ...an explode and catch fire when coming in contact with power lines, creating a dangerous situation. Visit cityofpaloalto.org/safeutility for tips on balloon safety. In the event of a power outage, check cityofpaloalto.org/outageinfo for immediate updates.

DON'T BE LEFT IN THE DARK.

COMING SOON: A new way to receive alerts and updates about power outages and other emergency notifications.

This summer, the City of Palo Alto Utilities (CPAU) will introduce a new Outage Management System (OMS) as an improved way to detect and respond to power outages and provide timely notifications and updates to our customers. Through this new system, you'll receive notifications through text messages, phone calls and emai...

SEE REVERSE SIDE FOR MORE INFORMATION

Rebates for High Winter Energy Costs - The City is offering rebates to residential gas and electric customers due to the extraordinarily high energy market costs this winter. Rebates will be calculated based on your January electric and/or gas utility bill amount. This will be automatically applied as a credit to your April or May utility bill as "Winter Rebate" with no action required by you. You may contact us directly to apply for additional financial assistance through payment arrangement plans, rate assistance, or a supplemental high bill financial assistance rebate the City is offering during this time. Visit cityofpaloalto.org/utilitiesassistance for details.

The prices that the City of Palo Alto Utilities (CPAU) and other utilities in the region pay for natural gas and electricity delivered to customers have risen significantly this year. Most residents will see the effects of these prices on their February bills. The City is offering several ways to help residents. Visit cityofpaloalto.org/efficiencytips for ways to save immediately and other steps you can take to reduce energy bill costs. Take advantage of free home assessments at cityofpaloalto.org/efficiencygenie, and visit cityofpaloalto.org/financialassistance to find alternative payment arrangements and other options for help with your utility bill.