

2025 CALIFORNIA ELECTRIC AND GAS UTILITY COSTS REPORT

AB 67 Annual Report to the Governor and Legislature

PUBLISHED OCTOBER 2026

California Public Utilities Commission

Contents

Overview 4
- Origins of the Report 4
- Electric IOU 2025 Authorized Costs 4
- Main Categories of Costs and Drivers of Change 6
- Natural Gas IOU 2025 Authorized Costs 10
- Main Categories of Costs and Drivers of Changes 11

Determining Electric Utility Ratepayer Costs 13
- General Rate Case Costs 14
- Authorized Rate of Return 15
- Rate Base 16
- Distribution Costs 17
- Utility Owned Generation Costs 18
- Nuclear Decommissioning Costs 19
- Generation & Power Procurement Costs 20
- Energy Supply 24
- Greenhouse Gas Compliance Costs and Allowance Proceeds 25
- Transmission Costs 26
- Electric Public Purpose Programs and other Customer Program Costs 28
- Bonds and Fees Costs 31
- Wildfire-Related Costs 32

Determining Natural Gas Utility Ratepayer Costs 34
- Gas Revenue Requirement Overview 34
- Core Gas Procurement Costs 35
- Gas Transportation Costs: Transmission, Distribution, and Storage 36
- Gas Public Purpose Programs and other Customer Programs Costs 38
- Greenhouse Gas Compliance Costs and Allowance Proceeds 38

Gas Public Purpose Program (PPP) Costs 39

Appendix 41

Overview

Origins of the Report

This 2025 California Electric and Gas Utility Costs Report, Assembly Bill (AB) 67 Annual Report to the Governor and Legislature (AB 67 Report), is submitted by the California Public Utilities Commission (CPUC) to fulfill statutory requirements.

Enacted pursuant to AB 67 (Levine, Chapter 562, Statutes of 2005), California Public Utilities (PU) Code Section 913 requires the CPUC to prepare a written report on the costs of programs and activities conducted by the four major electric and gas companies regulated by the CPUC. This legislation was enacted in part to determine the effect of various legislative and administrative mandates, and to provide more transparency into factors driving electric and gas rates.

This report and prior year reports are available at https://www.cpuc.ca.gov/AB67Report.

Highlights

This report features trends year over year in electric and gas costs, as well as trends in system average rates. Both costs and rates shift over time in response to a wide range of factors, including CPUC decisions, external commodity costs, and overall changes in utility market conditions.

Electric utility system costs (aka "revenue requirements") moved in different directions in 2025. Pacific Gas and Electric Company (PG&E) saw a moderate decline (-6%) in electric costs, driven primarily by lower generation-related revenue requirements. San Diego Gas and Electric Company (SDG&E) saw a slight increase (+1.8%) in electric costs, driven by substantial increases in distribution, transmission, and Public Purpose Program (PPP) costs, which were primarily offset by decreases in generation costs driven by changing market conditions including a reduction in resource adequacy scarcity. Finally, implementation of Southern California Edison Company's (SCE's) Test Year 2025 General Rate Case (GRC) drove a notable increase (+10.7%) in the SCE utility 2025 electric costs, especially due to increased spending on their distribution infrastructure.

Wildfire prevention costs have driven significant increases in utility rate base, especially since 2019. Wildfire prevention and mitigation spending, both capital (rate base) and operations and maintenance, continue to be a substantial driver of electric revenue requirements, with PG&E, SCE, and SDG&E each seeing substantial increases in wildfire-related costs since 2021, such as vegetation management, liability insurance, and infrastructure hardening (e.g. undergrounding, covered conductors, etc.). By 2025, wildfire-related revenue requirements accounted for 25.4% of PG&E's total revenue requirement, 13.7% for SCE, and 18.3% for SDG&E, underscoring the significant and growing impact of wildfire mitigation costs on customer rates.

Overall, electric rates for bundled residential customers have increased faster than inflation over the past decade. Average electric rates increased about 9% annually between 2020 and 2025, driven largely by distribution-level wildfire-related costs and rapidly expanding cost shifts associated with rooftop solar. From year-end 2024 to year-end 2025, SCE's bundled system average rates increased 3.4 cents per kilowatt-hour (¢/kWh) to 29.3 ¢/kWh, PG&E's decreased 0.1 ¢/kWh to 34.8 ¢/kWh, and SDG&E's increased 1.8 ¢/kWh to 35.1 ¢/kWh.[1]

Gas utility costs in terms of revenue requirements increased between 5% to 7% across all large gas IOUs (Southern California Gas Company (SoCalGas), PG&E and SDG&E) between 2024 and 2025, primarily driven by higher transportation costs approved in recent General Rate Case decisions. PG&E's system average rates for core gas customers has continued to increase over the past five years, but has remained relatively stable from 2023 through 2025 SoCalGas's and SDG&E's system average rates for gas customers peaked in 2023 at $18.68/MMBtu[2] and $21.17/MMBtu, respectively, but were lower than those peaks in 2025.

Affordability pressures for electric and gas customers were partially offset by substantial Cap-and-Invest bill credits in 2025 ($1.62 billion in electric bill credits and $971 million in natural gas bill credits) as well as substantial continued support for income-qualified customers through the income qualified bill discount programs (e.g. California Alternate Rates for Energy (CARE)). In addition, CPUC advocacy for lower costs in Federal Energy Regulatory Commission (FERC) transmission rate cases continues to generate substantial ratepayer savings annually. CPUC advocacy for lower transmission rates has generated over $6 billion in savings for California ratepayers since 2017, including large settlements in two recent PG&E transmission rate cases that resulted in almost $845 million being removed from rates.

This year's report cover recognizes that Caltrain marked a milestone year in 2025, which was the first full year of electrified service in San Francisco, San Mateo and Santa Clara.[3]

[1] Year-end 2025 rates are from PG&E Advice Letter 7684-E effective 9/1/25, SCE Advice Letter 5643-E effective 10/1/25, and SDG&E Advice Letter 4701-E effective 10/1/25.

[2] MMBtu = Million British Thermal Unit or roughly one dekatherm.

[3] Bouchard, 2025 Year in Review, Caltrain.com, https://www.caltrain.com/about-caltrain/2025-year-review-caltrain

Electric IOU 2025 Authorized Costs[4]

The 2025 revenue requirements, and percent change over prior year, for each of the three electric investor-owned utilities (IOUs) are shown in **Table 1.1**. These include both CPUC and (FERC) jurisdictional costs.

Table 1.1: Electric Utility Revenue Requirement Comparison ($000)[5]

Utility	2025	2024	Difference	
			$000	%
PG&E	19,079,591	20,341,236	(1,261,645)	-6.2%
SCE	19,403,170	17,530,066	1,873,104	10.7%
SDG&E	4,308,733	4,233,072	75,661	1.8%
Total	**42,791,494**	**42,104,374**	**687,120**	**1.6%**

Main Categories of Costs and Drivers of Change

Visual data representations below highlight key-year-over-year changes in various components of the revenue requirements.

[4] For historical report consistency, the term "cost" is being used to represent revenue requirements in this report. For more information about the difference between authorized costs and revenue requirements, as well as converting costs to revenue requirements, see the annual Senate Bill 695 Report (Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1).

[5] PG&E Advice Letter 7684-E, SCE Advice Letter 5643-E, and SDG&E Advice Letter 4701-E, effective 9/01/2025, 10/01/2025, and 10/01/2025, respectively.

Table 1.2: Electric Utility Revenue Requirement Comparison by Cost Category ($000)

Cost Category	PG&E		SCE		SDG&E	
	2025 Costs ($000)	% change from 2024	2025 Costs ($000)	% change from 2024	2025 Costs ($000)	% change from 2024
Generation	4,504,254	-15%	6,116,944	-1%	305,298	-61%
Distribution	11,237,376	-0.1%	10,085,739	13%	2,734,448	12%
FERC Transmission	2,291,479	-14%	1,341,594	20%	862,884	26%
Public Purpose Programs	581,635	0.1%	1,273,453	87%	405,891	29%
Nuclear Decommissioning	(19,019)	N/A	(915)	-113%	212	-85%
DWR[6] and Other Bond Charges	483,866	-28%	586,355	-1.5%	0	0%
Total	**19,079,591**		**19,403,170**		**4,308,733**	

Drivers of Electric Generation/Power Procurement Cost

- PG&E's decrease reflects the removal from rates of collections related to proceedings that impacted Generation revenue requirement, such as the Energy Resource Recovery Account (ERRA) Trigger.[7] ERRA Trigger mechanisms can increase or decrease rates when generation costs are significantly higher or lower than forecasted. PG&E collected a $256 million ERRA Trigger undercollection in 2024, but no additional ERRA Trigger collections were required in 2025, thus decreasing the revenue requirement compared to the previous year.
- SCE's drivers for the decrease are the implementation of the 2025 ERRA forecast and recovery of balancing accounts related to the ERRA forecast (such as the ERRA Balancing Account, Portfolio Allocation Balancing Account (PABA), and New System Generation Balancing Account (NSGBA).
- SDG&E's decreases are related to Investment Tax Credits from utility owned energy storage projects, a 2025 Power Charge Indifference Adjustment (PCIA) Voluntary Allocation Sales

[6] Department of Water Resources

[7] Each of the electric IOUs collects generation rates based on an ERRA Forecast application. If generation costs are significantly higher or lower than forecasted, the affected utility must file an ERRA Trigger notification with the CPUC.

Market Price Benchmark true-up, and a decrease in Local Generating Balancing Account (LGBA) undercollection.

Drivers of Electric Distribution Cost

- PG&E's decrease was mainly due to reduced distribution-related revenue requirement during 2025, such as the Wildfire and Gas Safety Costs Interim Rate Relief (WGSC IRR) and 2020 Wildfire Mitigation and Catastrophic Events (WMCE) no longer appearing in rates due to completion of amortization.
- SCE's increase in distribution revenue requirement was driven by the implementation of its Test Year 2025 GRC decision that included significant approved investments in distribution infrastructure.
- SDG&E's increase was caused by the February 2025 implementation of the SDG&E Test Year 2024 GRC decision into rates.

Drivers of Electric Transmission Cost

- PG&E's decrease is attributed to a much larger credit in the End-Use Customer Refund Balancing Account Adjustment (ECRBAA) in 2025 ($852.3 million), driven by a large settlement in PG&E's Eighteenth and Nineteenth Transmission Owner (TO 18 and TO19) rate cases, as compared to 2024 ($7.6 million), resulting in a reduction in rates of nearly $845 million.
- SCE's increase is due to two main factors: an approximately $147 million increase in its rate case true-up adjustment due to a large swing from a $133 million overcollections credit in 2024 to a $13 million undercollections charge in 2025 and a one-time cost adjustment in 2024 related to a $71 million Administrative and General (A&G) wildfire reserve expense credit that did not recur in 2025.
- SDG&E's increase is primarily attributed to higher rates in SDG&E's Sixth Transmission Owner (TO6) Rate Case. TO6 was filed at FERC in late 2024 with rates going into effect on June 1, 2025 that were significantly higher than SDG&E's previous rate case which ended on May 31, 2025.

Drivers of Public Purpose Programs Cost

- PG&E's PPP costs only slightly increased due to offsetting large increases and decreases across programs. Diablo Canyon Extended Operations contributed a large increase in PPP costs, offset by decreases in collections for CARE, Residential Uncollectible Balancing Account (RUBA) amortization, and the Electric Program Investment Charge (EPIC) program.
- SCE's increase in PPP costs were driven by the increase in the Energy Efficiency (EE) authorized revenue requirement and updates to SCE's CARE Balancing Account and Public Purpose Programs Adjustment Mechanism (PPPAM), as well as the incorporation of the Diablo Canyon Extended Operations Non-Bypassable Charge.

- SDG&E's increase in PPP costs is mainly due to the full amortization of 2024 overcollections in certain PPP-related balancing accounts (such as the Tree Mortality Non-Bypassable Charge (TNMBCBA) and Low-Income Energy Efficiency (LIEEBA) balancing accounts); larger collections for RUBA amortization and San Diego Regional Energy Network (SDREN); and the incorporation of the Diablo Canyon Power Plant Non-Bypassable Charge.

Changes in Average System Average Rates

The CPUC calculates the System Average Rate (SAR) for bundled customers by dividing the authorized bundled customer revenue requirement by the authorized bundled forecasted sales. The paragraphs below highlight bundled SAR trends over time:

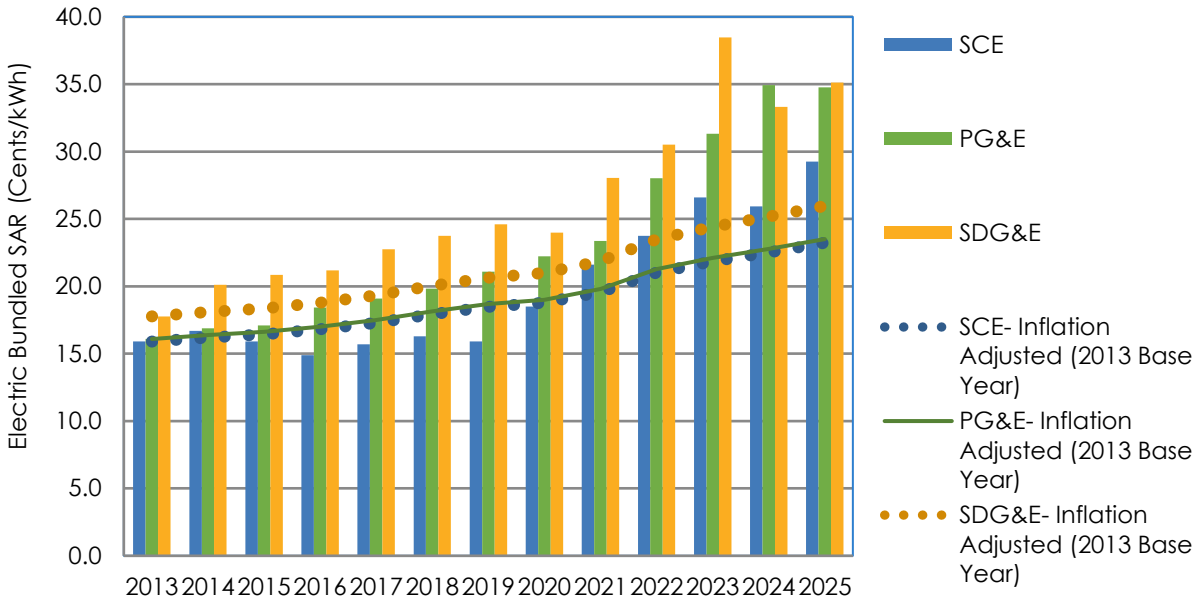
From 2020 to 2025, all three electric IOUs have had increases in bundled SAR above the rate of inflation, with the bundled SAR across the three electric IOUs increasing at an average annual rate of approximately 9 percent **(Figure 1.1)**, which is above the average annual inflation rate of about 4 percent over the same time period.[8] The figure shows actual rates in the columns and compares it to the reference year 2013 (shown in the dotted lines. Note that PG&E and SCE happened to have nearly the same rates in 2013, so their inflation adjusted lines are identical.

From year-end 2024 to year-end 2025, SCE's bundled SAR increased 3.4 cents per kilowatt-hour (¢/kWh) to 29.3 ¢/kWh, PG&E's decreased 0.1 ¢/kWh to 34.8 ¢/kWh, and SDG&E's increased 1.8 ¢/kWh to 35.1 ¢/kWh.[9]

[8] Rates are a function of both revenue requirement and sales. All three utilities experienced declines in bundled kWh sales over the 2020 – 2025 period, which generally leads to increased bundled system average rates when the bundled revenue requirement remains flat or rises. For more information about the effect of sales on rates, see the annual Senate Bill 695 Report (Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1).

[9] Year-end 2025 rates are from PG&E Advice Letter 7684-E effective 9/1/25, SCE Advice Letter 5643-E effective 10/1/25, and SDG&E Advice Letter 4701-E effective 10/1/25.

Figure 1.1: Trends in Electric Bundled System Average Rates (Cents/kWh)



Natural Gas IOU 2025 Authorized Costs

The 2025 revenue requirements, and percent change over prior year, for each of the three large gas utilities are shown in **Table 1.3** below.

Table 1.3: Natural Gas Utility Revenue Requirement Comparison ($000)

Utility	2025 CPUC	2024 CPUC	Difference	
			$000	%
PG&E	6,992,853	6,562,403	430,450	6.56%
SoCalGas	7,108,361	6,753,801	354,560	5.25%
SDG&E	1,046,027	974,884	71,143	7.30%
Total	**15,147,241**	**14,291,088**	**856,153**	**5.99%**

Main Categories of Costs and Drivers of Changes

Table 1.4: Natural Gas Utility Revenue Requirement Comparison by Cost Category ($000)

Cost Category	PG&E		SoCalGas		SDG&E	
	2025 Costs ($000)	(% change from 2024)	2025 Costs ($000)	(% change from 2024)	2025 Costs ($000)	(% change from 2024)
Core Procurement	1,018,832	0.08%	1,219,143	2.76%	169,808	-0.04%
Transportation	5,504,213	6.99%	5,427,989	8.43%	800,856	7.63%
Public Purpose Programs	469,808	17.59%	461,229	-17.87%	75,363	23.67%
Total	**6,992,853**		**7,108,361**		**1,046,027**	

Drivers of Core Procurement Costs

- PG&E saw a slight increase in core procurement revenue requirements from 2024 to 2025. This increase was due to an increase in independent storage provider (ISP) costs reported in the Other category.
- SoCalGas core procurement revenue requirements increased from 2024 to 2025. This was primarily due to an increase in the Core Gas Supply Portfolio[10] category.
- SDG&E had a small decrease in core procurement revenue requirements for 2025 in part because their total gas sales volume decreased compared to 2024.

Drivers of Transportation Costs

- PG&E's increase in transportation revenue requirements was primarily driven by the Distribution and Transmission categories due to increases approved in the 2023 GRC Decision (D.23-11-069).
- SoCalGas's increase in transportation revenue requirements was primarily driven by the Distribution and Transmission categories due to the implementation of the 2024 GRC Decision (D.24-12-074), effective February 2025 per Advice Letter (AL) 6430-G-A and 6430-G-B.

[10] The Core Gas Supply Portfolio manages procurement for core natural gas. It serves residential and small commercial customers by procuring natural gas from diverse basins in Canada, the Rockies, and the Southwestern United States. These purchases are on a daily, monthly, and longer-term basis. SoCalGas manages the Core Gas Supply Portfolio for SDG&E. SoCalGas's Core Gas Supply Portfolio also includes in-state storage. SoCalGas began integrating Renewable Natural Gas (RNG) into their Core Gas Supply Portfolio in 2024.

- SDG&E's increase in transportation revenue requirements was primarily driven by the Distribution, Other Balancing Accounts Balances, and Greenhouse Gas (GHG) Program categories due to the implementation of the 2024 GRC Decision (D.24-12-074) and higher GHG costs recorded in 2025.

Drivers of PPP Costs

- PG&E saw an increase in all reported categories for PPP revenue requirements in 2025.
- SoCalGas saw a decrease in PPP revenue requirements in 2025. This was due to the change in amortization for California Alternate Rates for Energy (CARE) program. In 2024, CARE amortization was an undercollected balance as compared to an over collected balance in 2025 resulting in a decrease in amortization.
- SDG&E saw an increase in PPP revenue requirements in 2025. This was mainly due to an increase in the Energy Efficiency (EE) Programs because of the funding of the SDREN as ordered in D.24-08-003.

Changes in System Average Rates

For the 2025 AB 67 Report, the utilities were asked to provide data on their system average rate (revenue requirements divided by sales) for core customers for the past five years.

PG&E's system average rate for core customers has continued to increase over the past five years. SoCalGas's and SDG&E's system average rates peaked in 2023 at $18.68/MMBtu and $21.17/MMBtu, respectively, but have been rising back to that average from 2024 to 2025.

Table 1.5 shows the system average rate for core customers for each of the utilities from 2021 to 2025. The difference seen here between PG&E and SoCalGas and SDG&E can be attributed to the changes in core procurement and transportation revenue requirements over the past five years. Resolution M-4874 increased the CPUC rate for gas customers from $0.00101/therm in 2024 to $0.00254/therm in 2025.[11]

[11] Public Utilities Code Section 431 and 432. The 2024 rate for the gas utility class was sufficient to sustain the estimated expenditures but not enough to maintain an adequate fund reserve balance. Therefore, the Commission increased the rate by $0.0015/therm for 2025.

Table 1.5: System Average Rate for Core Customers by Utility ($/MMBtu[12])

Utility	2021	2022	2023	2024	2025
PG&E	15.15	18.75	21.85	22.25	22.55
SoCalGas	14.07	17.92	18.68	15.07	17.71
SDG&E	15.90	19.91	21.17	17.02	20.94

Determining Electric Utility Ratepayer Costs

There are several procedural venues used to determine the major components of revenues that the utilities are authorized to collect through rates:

General Rate Cases: In GRCs, the CPUC evaluates the regulated operations of the utilities and determines the reasonableness of a utility's requests for changes in revenue needed to fund safe and reliable utility service. The GRCs are the main venue for looking at distribution costs.

- **Generation/Power Procurement cost cases, or ERRA proceedings**: The CPUC annually reviews each utility's fuel and power purchase forecast and, to the extent deemed reasonable, passes through those costs to bundled electric customers without any profit or mark-up for the utility. Some public purpose charges are also authorized here.
- **Transmission rate cases at the FERC:** The CPUC is required to allow recovery of all FERC-authorized transmission costs. Because transmission rates are subject to regulatory oversight by FERC, pursuant to AB 1890 (Brulte, 1996), the transmission revenue requirements of the various utilities that participate in the California Independent System Operator (CAISO) are determined in FERC proceedings, called TO rate cases.
- **Program Budget/Public Purpose Program Costs**: This category includes specific program area proceedings in which program budgets are determined. Most program specific costs are recovered through the distribution rate component, or a stand-alone rate component.
- **Bonds and Fees Costs:** Fees include charges levied by state and local governments. As of September 30, 2020, enough funds were collected from ratepayers to retire the Department of Water Resources (DWR) bonds, and consequently the DWR bond charge expired.

Table 2.1 shows the major components of the electric IOUs' 2025 revenue requirements broken out across these procedural venues. The following sections of the report review the various

[12] MMBtu = Million British Thermal Unit or roughly one dekatherm.

procedural venues in which these costs are calculated and highlight large drivers of changes in 2025 costs.

Table 2.1: 2025 Electric IOU Authorized Revenue Requirements ($000)

Revenue Component	PG&E	SCE	SDG&E
Generation/Power Procurement (ERRA, GRC)	4,504,254	6,116,944	305,298
Distribution- Wildfire Mitigation and Liability (GRC and other CPUC proceedings)	3,889,258	2,059,113	640,944
Distribution- Other (GRC)	7,348,118	8,026,626	2,093,504
Transmission- Wildfire Mitigation and Liability (FERC)	471,678	76,582	55,390
Transmission- Other (FERC)	1,819,801	1,265,012	807,494
Public Purpose Programs (other CPUC proceedings and statutes)	581,635	1,273,453	405,891
Bonds and Fees[13]	483,866 [14]	586,355	0 [15]
Nuclear Decommissioning	(19,019)	(915)	212
Total 2025 Revenue Requirement	**19,079,591**	**19,403,170**	**4,308,733**

General Rate Case Costs

GRC revenue requirements generally break down into the Distribution, Utility Owned Generation (UOG), and Transmission categories, and each is comprised of the following major cost elements: Operation and Maintenance (O&M), Depreciation, Taxes, and Return on Rate Base.[16]

[13] Includes Energy Recovery Bonds, Wildfire Fund Non-Bypassable Charge, and Wildfire Securitization.

[14] $61.836M of CPUC Regulatory Fees included in Distribution.

[15] SDG&E includes $91.87M in Wildfire Non-Bypassable Charges in their Distribution revenue requirement.

[16] Return on Rate Base: Authorized rate of return on rate base (ROR) is the weighted average cost of capital used to finance utility capital expenditures. Capital investment itself is returned via the collection of depreciation expense over the useful life of the asset. Rate Base: The rate base is the book value, after depreciation, of the generation, distribution, and transmission infrastructure owned and operated by the utility for the provision of electric service. Utilities earn a regulated Rate of Return (ROR) on rate base based on their capital structure, debt interest rates, and authorized return on equity (ROE). See Appendix Glossary in the 2024 AB 67 Report for definitions of GRC categories of costs.

Table 2.2 below summarizes the total 2025 CPUC-jurisdictional GRC revenue requirements as broken down into these cost categories for the three electric utilities.

Table 2.2: 2025 General Rate Case Revenue Requirements ($000)[17]

Cost Categories	PG&E	SCE	SDG&E
Operation and Maintenance	6,286,573	3,766,226	1,110,976
Depreciation	2,754,100	2,707,712	571,766
Return on Rate Base	2,288,765	2,952,022	437,274
Taxes and Franchise Fees	794,913	1,216,455	290,592
Total	**12,124,351**	**10,642,415**	**2,410,608**

This table excludes FERC-determined transmission revenue requirements.

The next two sections explore changes to the authorized rate of return (ROR) and rate base that influence Return on Rate Base for GRC cost categories.

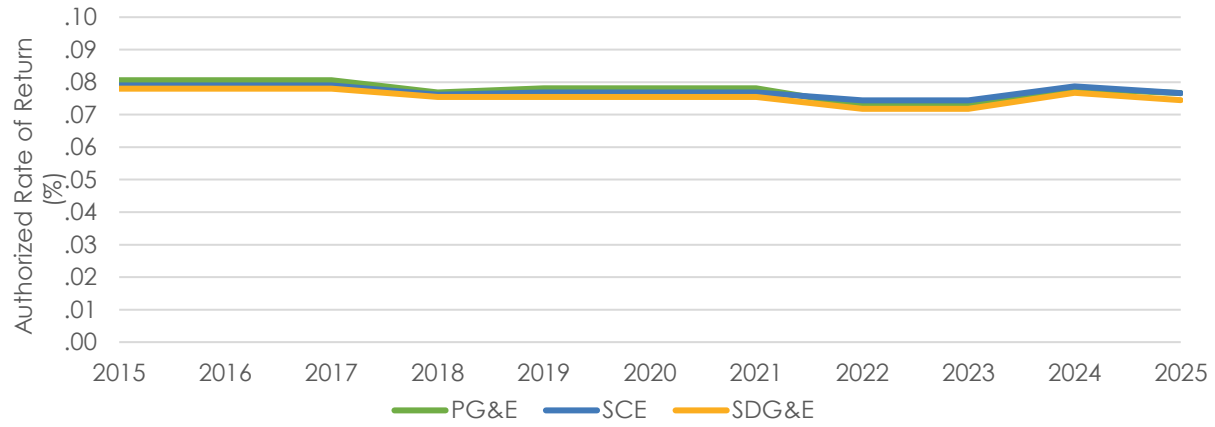
Authorized Rate of Return

Authorized rate of return on rate base is the weighted average cost of capital (CoC) used to finance utility capital expenditures. Cost of capital is the combination of the cost of debt and return on equity (ROE) as weighted according to the IOU's capital structure, all of which are authorized in separate Cost of Capital proceedings held every three years.

Figure 2.1 illustrates the CPUC authorized ROR since 2015 for major energy utilities. The figure does not include ROR authorized by FERC for IOU transmission systems; it includes only the ROR authorized by the CPUC for UOG and distribution. For 2025, the ROR for all three electric IOUs decreased when compared to 2024.

[17] Amounts shown include revenues adopted by the CPUC in the utilities' GRCs and additional revenues approved by the CPUC for inclusion in base revenues after the GRC Decisions were issued.

Figure 2.1: Trends in Authorized Return on Rate Base (ROR)



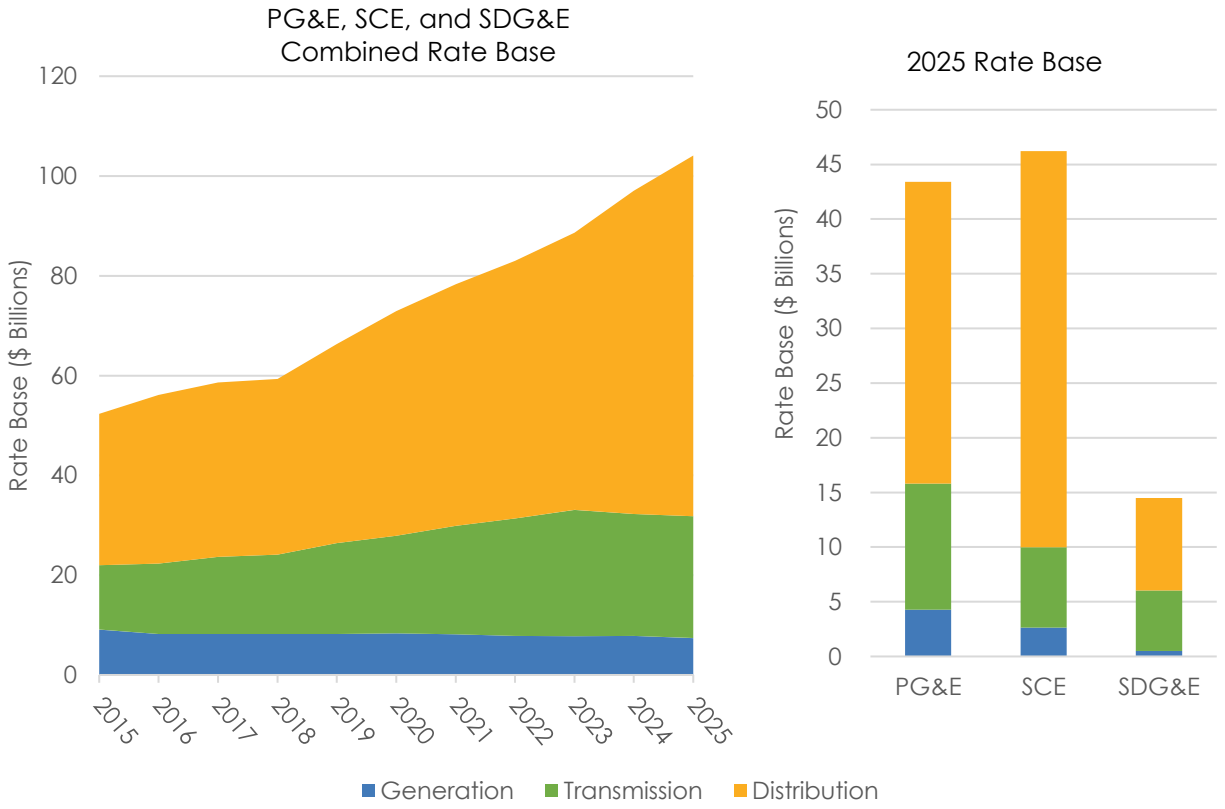
Rate Base

The rate base is the book value, after depreciation, of the generation, distribution, and transmission infrastructure owned and operated by the utility for the provision of electric service. Utilities earn a regulated ROR on rate base based on their capital structure, debt interest rates, and authorized return on equity.

As shown in **Figure 2.2** below, between 2015 and 2025, the utilities' rate bases increased in size from $52.3 billion to $104.1 billion, or a 99 percent increase in nominal dollars over the past decade, triggering corresponding increases in GRC revenue requirements both for the initial investments and the return on the rate base collected in the revenue requirement.[18] Utility rate base increases are driven by ordinary rises in the costs of utility components, like the costs of substation equipment or poles, and they are also driven by unusual or one-time costs such as major investments in new capital additions, such as the investment in wildfire mitigation programs, which represented a departure from the ordinary investment cycle.

[18] When adjusted for inflation, the 2015 rate base equals $71.1 billion. Therefore, an inflation-adjusted comparison of rate base from 2015 to 2025 indicates the rate base increased in size from $71.1 billion (adjusted for inflation from $52.3 billion) to $104.1 billion, or 46 percent.

Figure 2.2: Trends in Electric Utility Rate Base ($ Billions)



SCE's transmission rates are primarily 230 kV and above; whereas PG&E and SDG&E have transmission costs that are 115 kV and above.

Distribution Costs

Since 2015, the total distribution revenue requirement has increased, from $10 billion to $22.4 billion (**Figure 2.3**).[19] Over the same time period, depreciation expenses have experienced an approximate 3.4 percent average annual growth rate.[20] The increases in distribution costs are also due to capital additions, ongoing infrastructure modernization, and improvements to the distribution system for wildfire mitigation which have increased rate base, as discussed in the Rate Base section. The O&M for 2025 also includes recovery of certain catastrophic event expenses. **Table 2.3** below shows the contributions of distribution components to the 2025 revenue requirement.

[19] When adjusted for inflation, the 2015 total distribution revenue requirement equals $13.5 billion, which indicates distribution revenue requirement has increased approximately 66 percent from 2015 to 2025 (in 2025 dollars).

[20] Adjusted for inflation.

Figure 2.3: Trends in Distribution Revenue Requirement ($ Billions)

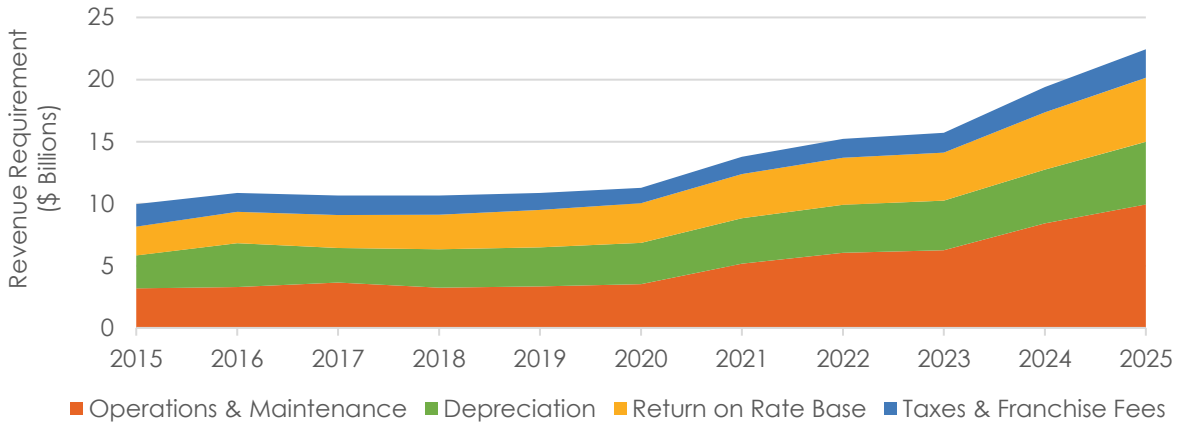


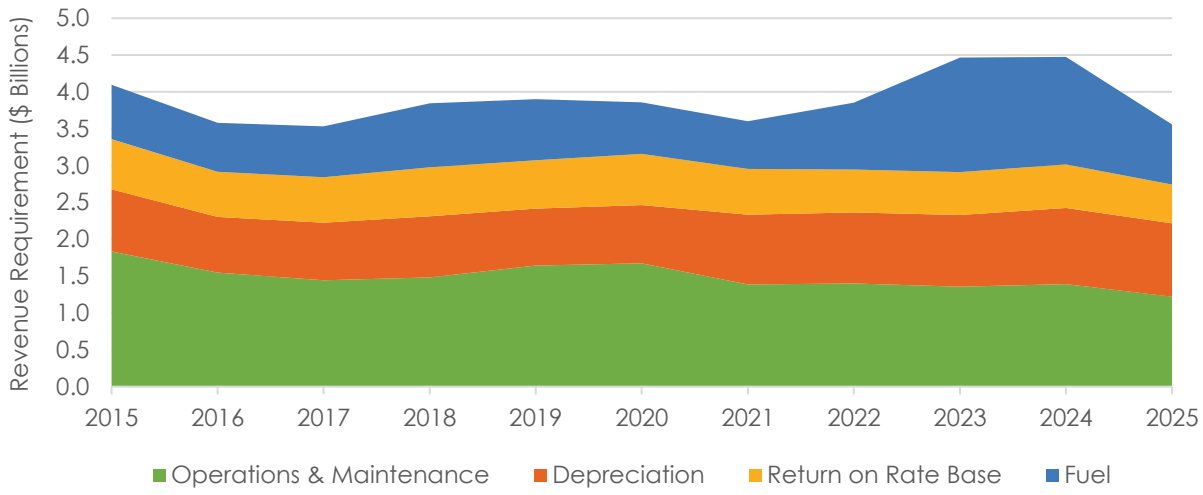
Table 2.3: 2025 Distribution Revenue Requirements ($000)

Cost Categories	PG&E	SCE	SDG&E
Operation and Maintenance	5,545,718	3,408,899	988,869
Depreciation	2,059,644	2,471,267	506,875
Return on Rate Base	1,977,859	2,774,443	399,639
Taxes and Franchise Fees	794,913	1,216,455	290,592
Total	**10,378,134**	**9,871,064**	**2,185,975**

Utility Owned Generation Costs

The revenue requirement for utility-owned (or retained) generation includes O&M costs, depreciation, and return on rate base related to these facilities. As older generation plants depreciate, costs of owning those plants decrease over time, even though costs of operating them may increase. As a result, the generation revenue requirement tends to decrease over time as shown in **Figure 2.4**. As new plants are built by the utilities or capital improvements are made to existing facilities, the capital costs of the new plants typically exceed the capital costs of the old plants they replace. After a slight decrease in 2024, 2025 saw a sharper decrease in fuel costs.

Figure 2.4: Trends in Utility Owned Generation Revenue Requirement ($ Billions)



Fuel costs are not included in the GRC but are reflected in generation revenue requirements

Following electric industry restructuring in the late 1990s and the utilities' divestiture of most utility owned fossil-fueled generation, UOG now accounts for only 6 percent of their combined revenue requirements. The 2025 generation revenue requirement for the electric IOUs is shown in **Table 2.4**.

Table 2.4: 2025 Utility Owned Generation Revenue Requirements ($000)

Cost Categories	PG&E	SCE	SDG&E
Operations and Maintenance	740,855	357,327	122,107
Depreciation	694,456	236,445	64,891
Return on Rate Base	310,906	177,579	37,635
Total	**1,746,217**	**771,351**	**224,633**

Nuclear Decommissioning Costs

The Nuclear Decommissioning Cost Triennial Proceedings (NDCTP) provide a venue for the utilities to forecast their expected decommissioning costs and for the reasonableness review of recorded costs at their respective nuclear facilities.

In D.23-09-004, the CPUC approved PG&E's 2021 NDCTP, authorizing a settlement agreement that, starting in 2023, eliminated the previously approved collection of $112.5 million in annual decommissioning revenue requirement from 2022 through 2029; and refunded $81 million to ratepayers from the nuclear decommissioning non-qualified trust fund.

On August 1, 2024, the CPUC approved D.24-08-001, the most recent NDCTP for San Onofre Nuclear Generating Station (SONGS) and Palo Verde, which had not requested any rate changes.

For additional background information, please see the "Nuclear Revenue Requirement" section in the previous 2024 AB 67 Report.

Apart from the O&M, depreciation and ROR authorized in GRC proceedings, and fuel costs authorized in ERRA proceedings, nuclear generation also results in additional costs, which are collected as separate revenue requirements.[21]

Additional costs collected as separate revenue requirements

- Fees for disposal and storage of spent nuclear fuel are required by the United States (U.S.) Department of Energy (DOE) for temporary and permanent storage facilities. Costs incurred for storage of spent nuclear fuel are currently reimbursed by DOE through claims for prior years consistent with PG&E's 2014 General Rate Case Settlement for Refunding DOE Litigation and Claims Net Proceeds to Customers. In D.07-03-044 the CPUC established the Department of Energy Litigation Balancing Account (DOELBA) to track litigation costs and proceeds received from DOE for the cost of spent nuclear fuel storage on site. SCE and PG&E have been directed to continue to report updated information regarding the net underlying costs supporting the payments from DOE through the litigation and claims process in each nuclear decommissioning cost triennial proceeding.
- Nuclear decommissioning of generating plants at the end of their operating lives is required by the United States Nuclear Regulatory Commission (NRC). To pay for these eventual decommissioning efforts, the utilities were required to establish Nuclear Decommissioning Trust Funds (NDTF). The funds placed into the NDTF are estimated in nuclear decommissioning cost triennial proceedings. The amounts authorized through the nuclear decommissioning costs are funded through rates during the operating lives of the nuclear plants.

Generation & Power Procurement Costs

The 2025 AB 67 Report provides a comprehensive analysis of the total costs of power procurement and generation costs in the utility revenue requirement.[22] The generation revenue requirements include utility owned (or retained) generation costs, as well as purchased energy and capacity costs. Energy restructuring in the late 1990s, and refined in the early 2000s, required the utilities to rely on purchased power for incremental electricity needs for most of their energy needs and enabled customer load to depart to Community Choice Aggregation (CCA) and Direct Access. As customers departed from bundled utility service at various points in the past two decades, the IOUs

[21] Nuclear Decommissioning and DOE Decommissioning & Disposal expenses are categorized with Bonds & Fees because they are collected separately.

[22] The data used in the Generation and Power Procurement section is based off forecast data, therefore includes data from 2026. The rest of AB 67 does not use forecast data, but rather actuals so therefore stops at 2025.

retained some long-term generation and purchased power commitments that were entered on behalf of the departed customers while they were served by IOUs.

Table 2.5: 2026 Total Revenue Requirements (in $000)

Power Procurement Categories	PG&E	SCE	SDG&E
ERRA Revenue Requirement (bundled only)	1,472,515	4,714,184	381,984
PABA Revenue Requirement (PCIA)[23]	2,904,459	858,837	145,485
Centralized Procurement	732,232	633,123	63,038
Total Generation Revenue Requirement[24]	**5,109,206**	**6,206,144**	**590,506**

Each IOU's generation revenue requirement is composed of three key elements. The Energy Resources Recovery Account recovers the costs to serve bundled load; the Power Charge Indifference Adjustment recovers costs for all the long-term procurement obligations from both the bundled and departed load for cost commitments incurred before the load departed.[25] Finally, there are several separate centralized procurement mechanisms that require the IOUs to procure resources on behalf of all customers in its territory regardless of when these customers departed from IOU service. These include the Cost Allocation Mechanism (CAM), Centralized Procurement Entity (CPE), Public Purpose Programs, Reliability Must Run Contracts, and Diablo Canyon Extended Operations.

Figure 2.5 shows the combined IOU revenue requirements for all generation and power procurement costs.[26] These revenue requirements show the market components of power procurement needed to meet the utilities' reliability requirements.

[23] The Portfolio Allocation Balancing Account (PABA) tracks the costs, market revenues, and imputed revenues of all generation resources (including utility-owned plants and long-term power purchase agreements) that were procured or approved by the California Public Utilities Commission (CPUC) for cost recovery via PCIA.

[24] The total generation revenue requirement presented in Table 2.5 diverges from generation and power procurement in Table 2.1 because several power procurement components are collected through the Public Purpose Programs and Bonds and Fees charges, which are listed separately.

[25] Bundled load refers to customers who receive both electric generation and delivery service from an IOU. Departed load refers to customers who no longer receive generation service from the utility (such as customers served by a CCA, Electric Service Provider, or their own generation resources) but who may still receive transmission and distribution service from the utility.

[26] See Appendix Glossary in 2024 AB 67 Report for definitions of various procurement types.

Figure 2.5: IOU Power Procurement Revenue Requirement by Cost Component ($ Billions)

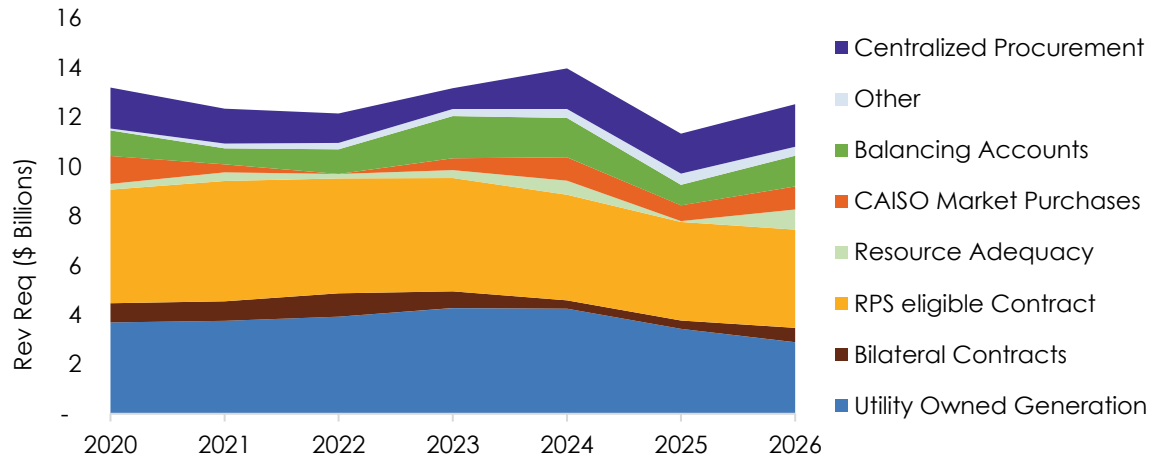
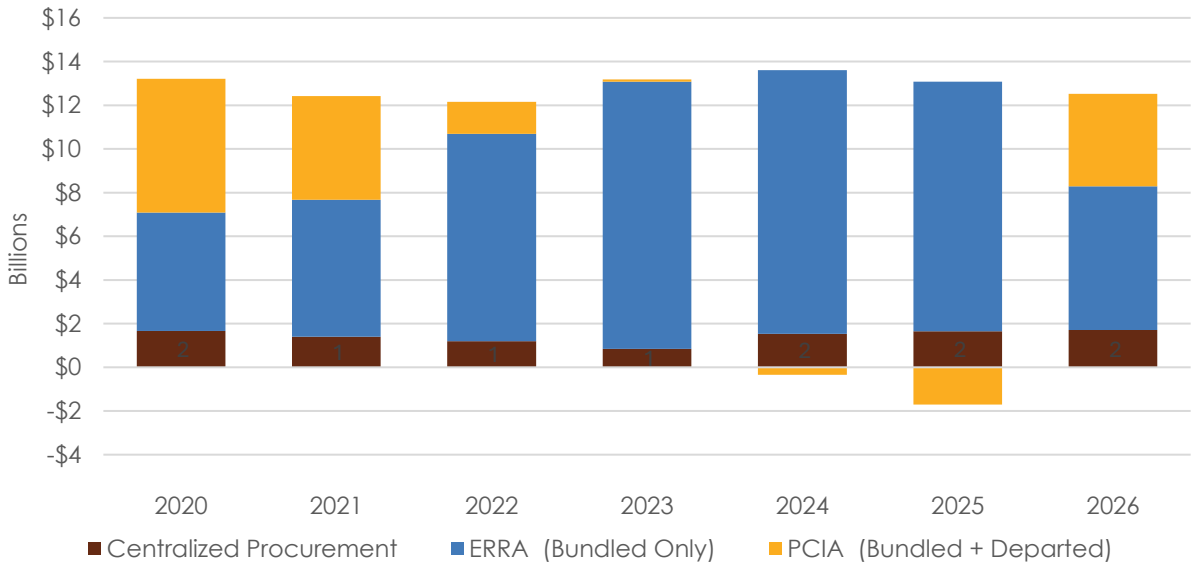


Table 2.5 shows the total generation revenue requirement of the three IOUs combined.[27] However, the total revenue requirement does not show the extent to which each of these components contribute to customer rates, because these components are charged to bundled and departed customers in varying proportions based on the type of cost recovery mechanism, to avoid cost shifting from load departure. **Figure 2.6** shows the IOU generation revenue requirements based on the cost recovery mechanisms. This view is essential because these revenue requirements are collected from bundled and departed load in varying proportions based on the year that a group of customers departed from bundled utility service.

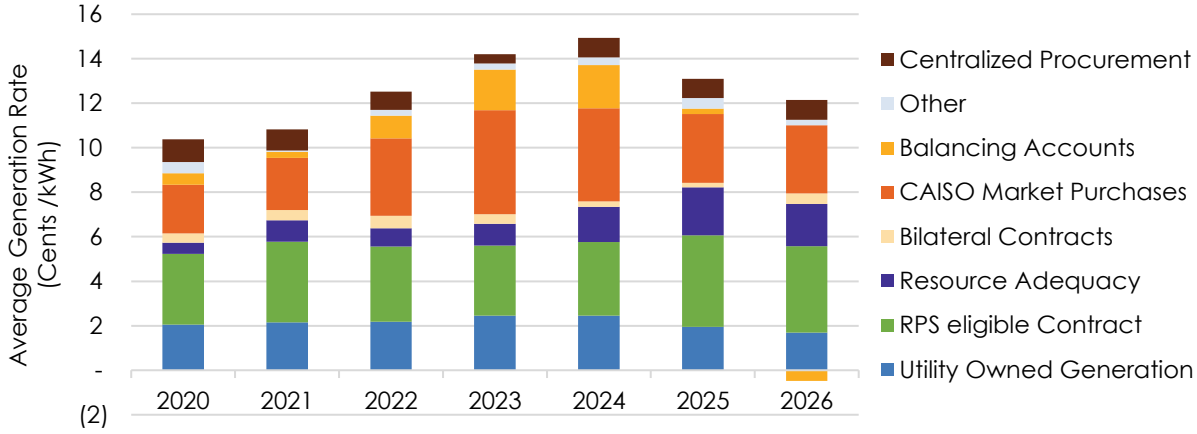
[27] Balancing accounts category includes the PABA and ERRA balancing account, which collect revenues and expenses from the ERRA and PABA revenue requirement to true up difference between forecast and actual expenditures.

Figure 2.6: Total Power Procurement Revenue Requirements by Cost Recovery Mechanism, All IOUs ($ Billions)



To understand which components of power procurement are driving generation rates, it is necessary to view the bundled-only costs on a $/kWh basis. As discussed above, the ERRA, PCIA and centralized procurement revenue requirements are collected from different bundled and departed load in varying proportions, based on the year customers departed from utility procurement service; the UOG, Renewables Portfolio Standard (RPS) eligible and Resource Adequacy (RA) components reflect the above market costs. **Figure 2.7** illustrates how much bundled customers pay for each of these components, demonstrating how the trends in these cost components drive the increase and/or decline in rates.

Figure 2.7: Components of Bundled Generation Rates All IOUs (Cents/kWh)



CAISO market costs are the most significant driver of fluctuations in the revenue requirements, accounting for $0.022 /kwh in 2020 and increasing to $0.46/kWh in 2023 at its peak, and declining

to $0.031 /kWh in 2026. The higher CAISO market costs were the result of tight market conditions, i.e. resource adequacy scarcity or natural gas price spikes, that had the effect of increasing energy prices during peak events in the CAISO market. As compared to **Figure 2.5,** where RPS eligible generation constitutes 32 percent of the revenue requirement, RPS constitutes a less significant portion of bundled rates because these costs are above market costs that are allocated to both bundled and departed load customers in the PCIA, along with Utility Owned Generation, Resource Adequacy and Bilateral Contracts.[28] Meanwhile, CAISO market purchases, RA and balancing accounts are much more significant components of the bundled generation rates.

Energy Supply

The overall energy supply attributed to the IOUs has continued to decrease since significant amounts load has departed to CCA service, in particular since 2017. The IOUs are required to optimize and sell-off the portions of their resource portfolios as load departs, which also serves to lower the overall PCIA obligation. UOG continues to represent a significant share of bundled energy supply but notably began to decline in 2023.

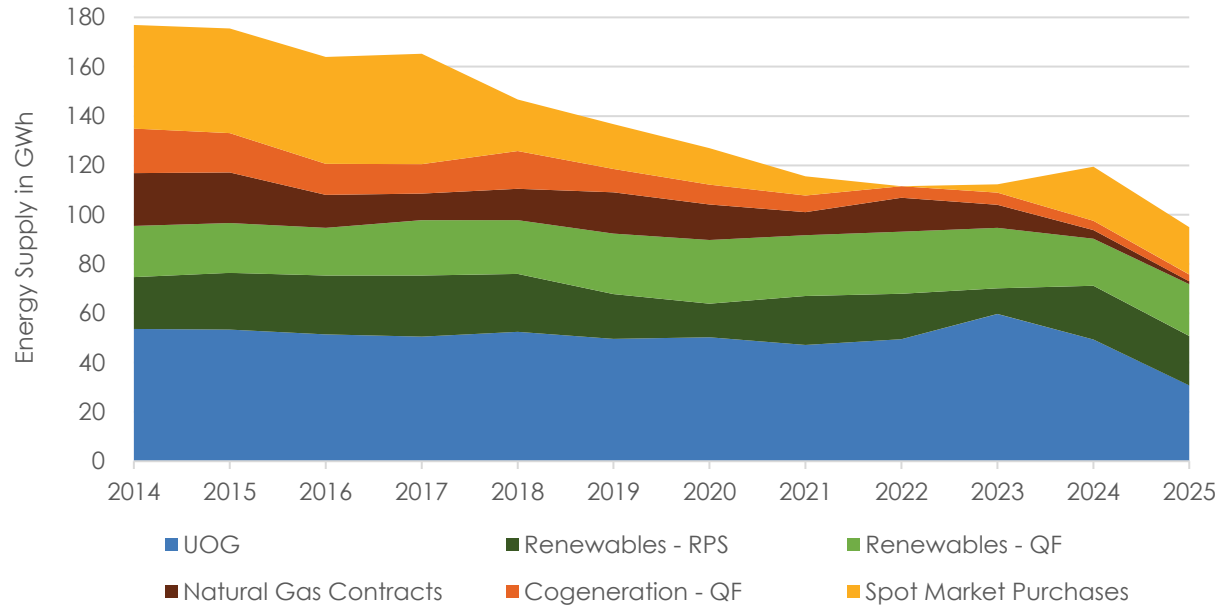
In the inverse, the share of RPS[29] resources and Renewable Qualifying Facilities stayed consistent. The amount of energy supply attributable to the CAISO spot market reflects each IOU's hedging position – the more open of a position an IOU is the more reliant they are on the spot market for their energy supply.

Figure 2.8 shows the total energy supply in gigawatt hours (GWh) of the combined IOUs. This figure represents total energy supply for all the IOUs and includes energy supply tied to the centralized procurement mechanism. However, centralized procurement represents a small share of overall energy supply.

[28] These costs are allocated to customer through the PCIA charge, based on the year the customer departed, such that the customer is only allocated costs for resources that were procured while they were in bundled service.

[29] For more information on RPS Costs and Cost Savings, see the Padilla Report to the Legislature: 2026 Reports to the Legislature.

Figure 2.8: Trends in IOU Energy Supply (GWh) - Decreasing with Load Departure to CCAs



Greenhouse Gas Compliance Costs and Allowance Proceeds

Beginning in 2014, the electric utilities introduced Cap-and-Invest Program related costs into electricity rates and began distributing program benefits in the form of allowance proceeds to residential customers via the California Climate Credit, applied to customer bills twice a year.

Allowance proceeds are generated from the sale of allowances allocated annually at no cost to the IOUs by California Air Resources Board (CARB). Small Business customers and emissions-intensive trade-exposed industrial customers also began to receive credits in 2014. Historically, a small portion of the proceeds were used to fund solar and/or solar/battery programs for disadvantaged and low-income customers such as the Self-Generation Incentive Program (SGIP) and the Solar on Multifamily Affordable Housing (SOMAH) program, as directed by statutes. AB 1207 (Stats. 2025, Ch. 748) removed CPUC's ability to use up to 15 percent of the Cap-and-Invest Program proceeds for clean energy and energy efficiency projects, effective July 1, 2026.

Overall, including both indirect and direct costs, credits from the Cap-and-Invest Program are expected to offset any cost increases for residential electric customers.[30]

Utilities accrue costs for the Cap-and-Invest Program as both direct and indirect costs. In 2025, the electric utilities collectively included approximately $147 million in direct GHG costs into rates to bundled customers and returned approximately $866 million in allowance proceeds to bundled customers in the form of customer credits (see **Table 2.6**).

[30] Legislative Analyst's Office (LAO). Cap-and-Trade: Overview and Affordability Considerations. February 26, 2025. More info at: https://lao.ca.gov/handouts/resources/2025/Cap-and-Trade-Overview-and%20Affordability-022625.pdf

Table 2.6: 2025 Summary of Greenhouse Gas Costs and Allowance Proceeds (in $)[31]

Utility	2025 Electric GHG Direct Costs Revenue Requirement[32]	2025 Electric Proceeds Distributed to Bundled Customers	2025 Electric Proceeds Distributed to Unbundled Customers
PG&E	Confidential	315,720,304	414,557,072
SCE	Confidential	485,956,713	155,384,320
SDG&E	Confidential	84,744,072	162,373,933
Total	**147,340,605**	**866,421,089**	**732,315,325**

The electric utilities also returned approximately $732 million in allowance proceeds to unbundled customers in customer credits. Customers also incur indirect costs for the Cap-and-Invest Program when utilities purchase power from the spot market or other market purchases, where the cost of compliance is included as part of the purchase price. These Cap-and-Invest Program compliance costs are included in the "Generation/Power Procurement" row of **Table 2.1** (2025 Electric IOU Authorized Revenue Requirements) but are not reported separately in this section.

Transmission Costs

The CPUC is the statutorily designated agency representing the interests of California retail ratepayers at FERC,[33] advocating for just and reasonable rates for California consumers in TO rate cases. For additional background information, please see the "Transmission Revenue Requirement" section of the 2024 AB 67 Report.

Transmission revenue requirements for the IOUs have been trending upward since 2017, increasing at an average annual growth rate of 2.3 percent for PG&E, 4.1 percent for SCE, and 6.0 percent for SDG&E as shown in **Figure 2.9**.

Figure 2.9: Trends in Total Transmission Revenue Requirements[34]

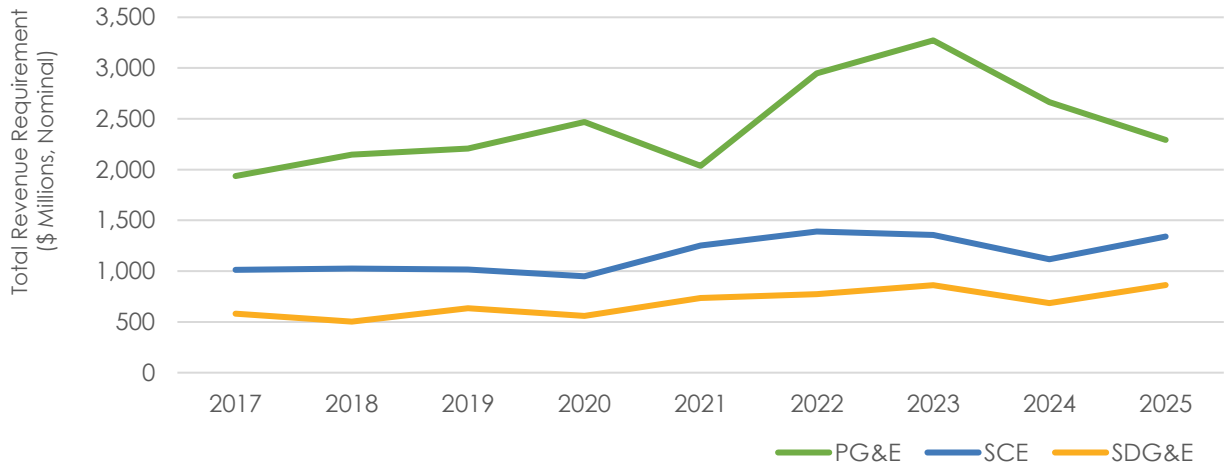
[31] Proceeds recorded through September 30, 2025 and estimated through December 31, 2025. Costs recorded through July 31, 2025 and estimated through December 31, 2025 for SCE; forecast for PG&E and SDG&E. Costs for bundled customers only. Bundled proceeds include residential and small business California Climate credits and CA Industry Assistance.

[32] Due to confidentiality, some cells have cost values that were left blank.

[33] CPUC Code, Section 307(b).

[34] The data represented in this graph are for the transmission owners' total revenue requirements. In 2025, this was $2,291,479,000 for PG&E, $1,341,594,000 for SCE, and $862,884,000 for SDG&E.

The noticeable dips in TRR for each utility from one year to the next is typically attributed to refunds in rate case settlements at FERC. This is especially noticeable in PG&E's TRRs from 2023 to 2024 and 2024 to 2025, which reflect settlement refunds in the TO21 and TO18 rate cases, respectively.



PG&E's Total Transmission Revenue Requirement (TRR) in 2025 was $2.29 billion, $370 million less than the total TRR of $2.66 billion in 2024.[35] The 2025 Total TRR was lower due to a much larger credit in the ECRBAA in 2025 ($852.3 million) from a multi-year rate case settlement, as compared to 2024 ($7.6 million), resulting in nearly $845 million in reduced rates in 2025 compared to 2024 due to the ECRBAA. This reduction in rates is due to the CPUC's and other rate case intervenors' advocacy in the TO18 rate case.

FERC approved the settlement in SCE's most recent TO formula rate case in September 2020. SCE's total TRR in 2025 was $1.34 billion, a 20.2 percent increase from 2024's total TRR of $1.12 billion. The increase in SCE's total TRR was primarily due to two factors: a $147 million increase in the true-up adjustment and a one-time cost adjustment in 2024 related to a $71 million A&G wildfire reserve expense credit which did not recur in 2025.

Similar to PG&E's TO20 rate case, as part of SCE's TO rate case settlement in 2020, SCE implemented the Stakeholder Review Process (SRP), enabling stakeholder review of its Five-Year Investment Plan for transmission projects and costs. Very similar to PG&E's Stakeholder Transmission Asset Review (STAR) Process, the SRP expired in 2023, succeeded by the Transmission Project Review (TPR) Process.[36]

[35] The total TRR includes the transmission owner (TO) rate case, which encompasses the total cost of construction, maintenance, and operation of providing transmission service with a rate of return on investment; reliability service costs; Transmission Access Charge Balancing Account Adjustment (TACBAA); and credits to ratepayers from the Transmission Revenue Balancing Account Adjustment (TRBAA), which is primarily from revenues paid by entities outside of California to wheel electricity through the CAISO grid. PG&E's TO18 settlement, for rates dating back to 2017, resulted in over $850 million of refunds into 2025 rates via the End-Use Customer Refund Balancing Account Adjustment (ECRBAA).

[36] For additional information on the TPR Process, please see the "Transmission Revenue Requirement" section in the 2024 AB 67 Report.

SDG&E's TO6 rate case has been in effect since June 1, 2025.[37] SDG&E's Total TRR in 2025 was $852 million[38], a 25.9 percent increase from 2024's Total TRR of $677 million. The higher TRR is primarily attributed to higher rates in SDG&E's TO6 rate case. Filed at FERC in late 2024, the TO6 rates starting on June 1, 2025, were significantly higher than SDG&E's previous rate case, which ended on May 31, 2025. The TO6 Rate Case Settlement recently filed at FERC was reached through the advocacy of the CPUC and other intervenors and will result in a true-up refund with interest leading to a lower TRR in the future.

Other factors leading to a higher TRR include a decrease in the true-up adjustment in 2025 versus 2024 and increases in Prior Year Revenue Requirement (PYRR), Transmission Rate Base, O&M, A&G and Depreciation Expense compared to the prior year.

Electric Public Purpose Programs and other Customer Program Costs

The Demand-Side Management (DSM) initiatives and customer programs overseen by the CPUC encompass a mix of energy efficiency, demand response (DR), and distributed generation (DG) programs, serving all sectors of California's economy.

Table 2.7 shows the DSM and customer program costs recovered in rates. The table includes all programs categorized by the utilities as Public Purpose Programs as well as some of the programs categorized by the utilities as Distribution (such as Demand Response). Thus, values in the Total line of Table 2.7 differ from the values for Total PPP shown in Table 1.2 and Table 2.1.

[37] SDG&E filed its TO6 rate case on October 30, 2024, and it took effect on June 1, 2025. A settlement was filed at FERC in March 2026.

[38] This $852 million is from the Total Rate Case Revenue Requirement excluding franchise fees.

Table 2.7: 2025 Demand Side Management and Customer Programs Costs ($000)

Program	PG&E	SCE	SDG&E	Total
Energy Efficiency[39]	191,950	477,467	(1,000)	668,417
Demand Response	199,910	51,471	7,520	258,901
Self-Generation Incentive Program[40]	0	0	0	0
Electric Program Investment Charge	67,276	76,035	16,280	159,591
California Alternative Rates for Energy Administration[41]	(233,986)	115,496	196,348	77,858
Energy Savings Assistance	(13,761)	92,462	17,428	96,129
Other PPP Programs[42]	593,155	493,518	102,046	1,188,719
Other Regulatory[43]	(287,609)	159,222	127,066	(1,321)
Total	**516,935**	**1,465,671**	**465,688**	**2,448,294**

[39] These collection amounts for Energy Efficiency will not necessarily match spending amounts, primarily because IOUs collect funds from ratepayers based on authorized budgets, regardless of actual expenditures.

[40] IOUs already collected the SGIP budget in rates through 2024, and continue to spend it down, but did not collect new revenue in 2025.

[41] Costs shown for California Alternative Rates for Energy Administration include CARE Balancing Account balances. Such balances can be either over- or under-collected and can vary from year to year and from utility to utility.

[42] For all three utilities, the largest program costs in the Other PPP Programs category are costs to support extended operation of Diablo Canyon Power Plant ($365 million for PG&E, $283 million for SCE, and $61 million for SDG&E).

[43] Programs included in the Other Regulatory Programs category vary for each utility. For PG&E, the largest amount in this category is from the Demand Response Expenditures Balancing Account (DREBA) Emergency Load Reduction Program sub-account (a credit of $180 million); for SCE, the Charge Ready Programs ($77 million in costs); and for SDG&E, Post-1997 Electric Energy Efficiency ($49 million in costs).

Highlights Across Programs

Energy Efficiency Program activities in 2024 and 2025 resulted in reported energy savings of approximately $1,522 million in Total System Benefit, equivalent to 950 GWh, 215 megawatt (MW), and 139 million therms (MMtherms). According to the U.S. Environmental Protection Agency (EPA)[44], these electricity savings are comparable to the carbon dioxide (CO_2) emissions from the annual electricity use of approximately 162,412 homes. The associated natural gas savings are roughly equivalent to avoiding emissions equal to about 18 percent of a coal power plant's annual output.

Demand Response: In the last IOU DR Applications, the CPUC approved the IOUs' Demand Response programs and budgets for program years 2024 through 2027. SCE was authorized $812.02 million, PG&E was authorized $616.01 million, and SDG&E was authorized $120.65 million. In 2025 the Commission launched a new DR rulemaking to Enhance Demand Response in California (R.25-09-004). The overall objective of the rulemaking is to evaluate and enhance the consistency, predictability, reliability, and cost-effectiveness of demand response resources.

Customer Generation: The customer generation programs that provide financial incentives to participating customers include the Disadvantaged Communities – Single-family Solar Homes (DAC-SASH) Program, the Self-Generation Incentive Program (SGIP), and the Solar on Multifamily Affordable Housing (SOMAH) program. In addition, net energy metering (NEM) and the newer net billing tariff (NBT) provide customer-generators with bill credits for power generated by their onsite systems that is fed back into the grid as well as the ability to offset load behind-the-meter.

Income Qualified Programs:

- **California Alternate Rates for Energy (CARE)** provides a nearly 40 percent bill discount to nearly 26 percent of California electric customers. PG&E's CARE subsidy in 2025 was approximately $1.2 billion (electric and gas combined), compared to $867 million for SCE, $212 million for SDG&E (electric and gas combined), and $196 million for SoCalGas.
- **Family Electric Rate Assistance (FERA)** is an electric rate assistance program that provides an 18 percent discount on electric bills to income-qualified households. PG&E's FERA subsidy in 2025 was approximately $21.2 million, compared to $15.0 million for SCE, and $5.2 million for SDG&E. At the end of 2025, approximately 112,295 households were enrolled in FERA out of an estimated 753,878 eligible households.[45] IOUs have not yet met the 60 percent enrollment goal by 2025 and are exploring ways to increase program enrollment and meet the 2026 enrollment goal.
- **Energy Savings Assistance Program (ESA)**: The ESA program is a no-cost to participant direct-install energy efficiency program that provides home weatherization services and energy

[44] Greenhouse Gas Equivalencies Calculator: Greenhouse Gas Equivalencies Calculator | US EPA

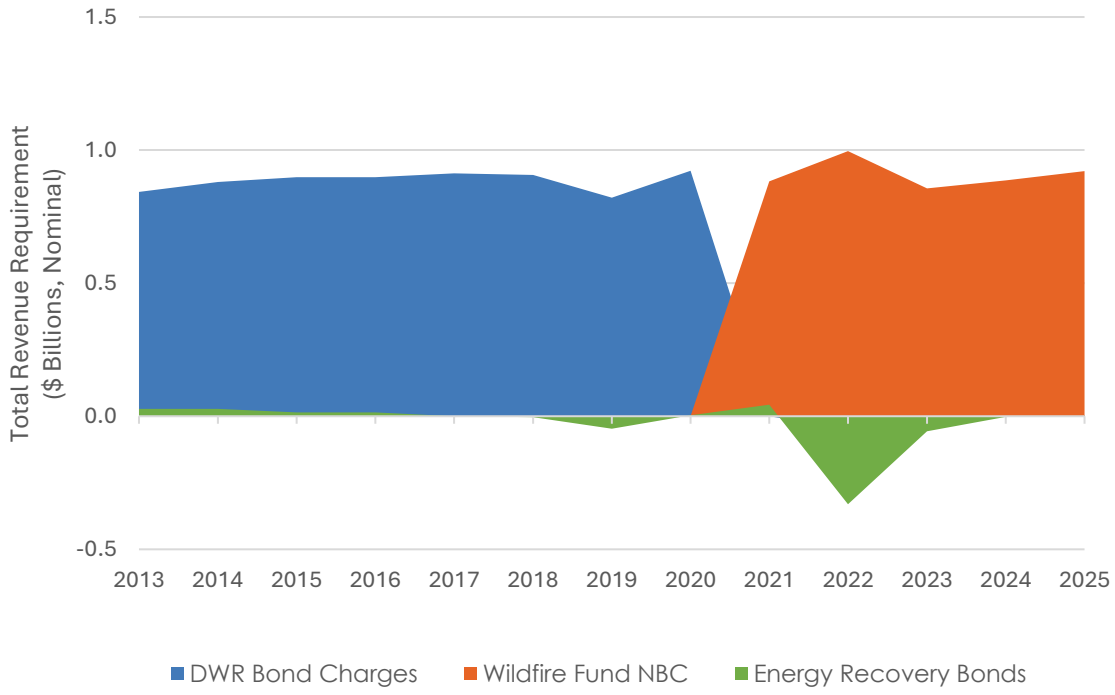
[45] Source: December 2025 Investor-Owned Utility FERA Monthly Reports, posted to Docket A.19-11-003.

efficiency measures to help income-qualified households conserve energy, reduce their energy costs/utility bills, and improve the health, comfort, and safety of the home. In 2025, the ESA program served nearly 200,000 households and achieved about 64 GWh and 3.4 MMtherms of annual energy savings.[46] This was about a 5 to 20 percent increase from program year 2024. These more modest (compared to previous years) year-over-year increases reflect the increasing stability of these programs as recent CPUC policy changes have been implemented by the IOUs and their contractors.

Bonds and Fees Costs

During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the recovery of costs of energy restructuring and the high-priced energy contracts entered into to emerge from the energy crisis of 2000-2001. Since the energy crisis, the bond costs to cover the energy crisis costs have decreased from a peak of approximately $2 billion in 2005 to approximately $900 million through September 2020 and then were retired in 2021. Beginning in October 2020, the energy crisis related bond charges were replaced by the Wildfire Fund Non-Bypassable Charge, which is a revenue requirement of $921.2 million for 2025, as illustrated in **Figure 2.10**, collected across the three IOUs.

Figure 2.10: Trends in Bond and Wildfire Fund Expenses ($ Billions)



[46] Final household treatment numbers will be available in IOU Annual Reports for Program Year 2025 on May 1, 2026.

Table 2.8 shows the 2025 revenue requirement for the CPUC Reimbursement Fee and Franchise Fee and Uncollectible Surcharge.[47] The CPUC Reimbursement Fee is the annual fee to be paid by utilities to fund their regulation by the CPUC (California Public Utilities Code (PUC) Section 401-443). The surcharge to recover the cost of that fee is ordered by the CPUC under authority granted by PU Code Section 433.

Table 2.8: 2025 Regulatory Fees ($000)

Fee	PG&E	SCE	SDG&E	Total
CPUC Reimbursement Fee	61,836	63,308	0[48]	125,144
Franchise Fee & Uncollectible Surcharge	204,657	22,423	117,233	344,313

Wildfire-Related Costs

Prior to 2020, wildfire prevention spending by utilities was not broken out separately from other utility spending. Although these costs are included in Table 2.1 at the beginning of Section II (for example, in the rows denoted by the term "wildfire" next to Distribution and Transmission revenue requirements), they are presented here to illustrate the overall trend in wildfire-related costs and the share of total revenue requirement they represent.

- For PG&E and SCE, significant wildfire prevention-related operating expenses, including vegetation management efforts and wildfire liability insurance coverage, began to appear as separate lines in revenue requirement, and ultimately in rates, relative to total revenue requirement starting in 2021.
- For SDG&E, the revenue requirement associated with 2019-2022 wildfire mitigation spending tracked in memorandum accounts began to appear in rates in 2025.

Wildfire-related revenue requirement for recent years is shown in **Table 2.9** below. **Table 2.10** shows, for each utility, how much of total 2025 revenue requirement is related to wildfire.

[47] Franchise fees are fees paid by a privately-owned utility to cities and counties for the right to use or occupy public streets and roads, and for permission to provide service in their jurisdictions. Uncollectibles include accounts receivable that have defaulted or cannot be collected.

[48] CPUC fees are not part of SDG&E's billed rate and instead are a separate surcharge, called the State Regulatory Fee, included on customer bills, similar to the California Energy Commission (CEC) Fee, called the State Surcharge Tax. The Total Revenue Requirement only reflects items that are included in SDG&E's billed rates.

Table 2.9: Wildfire-Related Revenue Requirement, 2019-2025 ($000)[49,50]

Utility	2019	2020	2021	2022	2023	2024	2025
PG&E	74,600	743,289	2,610,145	3,263,238	3,179,780	5,404,304	4,844,102
SCE	288,505	1,006,463	1,547,544	1,634,564	2,007,290	2,930,405	2,658,742
SDG&E	126,127	182,419	321,511	376,115	371,738	412,873	788,151

Table 2.10: 2025 Wildfire-Related Revenue Requirement ($000)

Utility	2025 Wildfire-Related Revenue Requirement ($000)	2025 Total Revenue Requirement ($000)	2025 Wildfire-Related Revenue Requirement % of Total Revenue Requirement
PG&E	4,844,102	19,079,591	25.4%
SCE	2,658,742	19,403,170	13.7%
SDG&E	788,151	4,308,733	18.3%

[49] Source for 2019 through 2024 amounts: IOU data responses to SB 695 Report.

[50] The wildfire revenue requirement includes recovery for catastrophic event memorandum account (CEMA) costs. CEMA proceedings include all CEMA-eligible costs, a small portion of which may be unrelated to wildfire, such as restoration of service after winter storms.

Determining Natural Gas Utility Ratepayer Costs

The CPUC determines the reasonableness of natural gas utility operational costs, gas cost allocation among customer classes, and gas rate design for PG&E, SDG&E, and SoCalGas.

Natural gas utility costs are categorized into three main components: 1) core procurement costs, 2) costs of operating the natural gas transportation system and providing customer services, and 3) costs associated with gas public purpose programs.

Gas Revenue Requirement Overview

Table 3.1 shows the 2025 natural gas revenue requirement by components.

Table 3.1: 2025 Gas Revenue Requirement by Key Components ($000)

Component Type	PG&E	SoCalGas	SDG&E	Total
Core Procurement	1,018,832	1,219,143	169,808	2,407,783
Transportation	5,504,213	5,427,989	800,856	11,733,058
Public Purpose Programs	469,808	461,229	75,363	1,006,400
Total	**6,992,853**	**7,108,361**	**1,046,027**	**15,147,241**

Table 3.2 shows the historical natural gas revenue requirements from 2019 to 2025.

Table 3.2: Historical Revenue Requirement by Utility ($000)

Utility	2019	2020	2021	2022	2023	2024	2025
PG&E	4,587,569	4,484,635	4,926,879	5,655,409	5,354,371	6,562,403	6,992,853
SoCalGas	5,042,690	5,009,906	5,637,250	6,832,542	8,418,390	6,753,801	7,108,361
SDG&E	666,198	772,278	811,019	1,003,908	1,225,380	974,884	1,046,027
Total	**10,296,457**	**10,266,819**	**11,375,148**	**13,491,859**	**14,998,141**	**14,291,088**	**15,147,241**

Core Gas Procurement Costs

Under the Natural Gas Act of 1978 (NGA), the cost of natural gas commodity is deregulated. The FERC regulates interstate transmission costs to California, while the CPUC regulates intrastate transmission and distribution costs.

Unlike its process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Natural gas is purchased through wholesale markets, where prices fluctuate based on market conditions. Utilities procure gas supplies for core gas customers (primarily residential and small commercial) only. The largest component of core procurement costs is the cost of the commodity itself; other components include interstate pipeline capacity and hedging. Utilities recover these costs with no direct mark-up. However, gas utilities may earn a shareholder incentive if they procure natural gas at prices below set benchmarks. Procurement rates are updated monthly through advice letter filings based on a 30-day price forecast.

Core procurement costs have been volatile in recent years. An interstate gas pipeline connecting Texas to Southern California ruptured and remained out of service from August 2021 until February 2023. That loss increased competition for the remaining pipeline capacity, increasing prices in Southern California. The Russian invasion of Ukraine in February 2022 contributed to a period of rising natural gas prices across the country as the U.S. further ramped up exports of liquified natural gas (LNG) to compensate for reductions in Russian gas supplies to Europe. In California, a hot summer in 2022 was followed by a cold fall and winter, leading to gas prices reaching a peak in December 2022 and January 2023. The return to service of the interstate pipeline, increased storage levels, milder winters in California, and an increase in natural gas production across the country led to lower gas prices in 2023 and 2024.

The CPUC issued D.26-02-058 on February 26, 2026, which states that in the event of a winter gas price spike, PG&E, SoCalGas, and SDG&E must impose a temporary cap on their Core Procurement Charge for that month. In the event of a gas price spike, PG&E, SoCalGas, and SDG&E must notify customers within one business day through an alert on the utility's website and sent via email and text. Within 30 days this alert must be stated during customer service calls, published in a print newspaper, and/or published via paid radio or broadcast television advertisements. Within two business days, the utilities must also make information on resources provided by local governments and health departments available to their customers on their websites. In addition, if PG&E or SoCalGas observe a 150 percent increase in forward prices for the coming winter, they must inform customers that their bills may be higher than usual at the earliest known date but no later than October 15 of each year.[51] **Table 3.3** shows historical revenue requirement for core procurement from 2019 to 2025.

[51] D.26-02-058, OP 2, 4, and 6.

Table 3.3: Historical Core Procurement Revenue Requirement ($000)

Utility	2019	2020	2021	2022	2023	2024	2025
PG&E	935,782	770,337	865,924	1,110,950	986,787	1,018,046	1,018,832
SoCalGas	1,134,044	923,497	1,417,147	2,365,840	3,408,039	1,186,439	1,219,143
SDG&E	157,016	128,346	192,212	327,665	474,126	169,879	169,808
Total	**2,226,842**	**1,822,180**	**2,475,283**	**3,804,455**	**4,868,952**	**2,374,364**	**2,407,783**

PG&E saw an increase of 0.08 percent for core procurement revenue requirement from 2024 to 2025 due to higher independent storage provider (ISP) costs in the Other category. The increase in ISP costs resulted from a greater amount of core storage inventory under contract in 2025 as compared to 2024. PG&E's average procurement rate decreased from $4.78/MMBtu in 2024 to $4.23/MMBtu in 2025. Additionally, the Core Incentive Mechanism category decreased due to no shareholder award being issued in 2025, compared to approximately $10.2 million awarded in 2024.

SoCalGas core procurement revenue requirement increased by 2.76 percent from 2024 to 2025. This was driven by a higher Weighted Average Cost of Gas (WACOG), which led to an increase in the Core Gas Supply Portfolio category. While the WACOG was more stable month-to-month in 2025, the yearly average was higher, pushing the average procurement rate from $3.50/MMBtu in 2024 to $3.93/MMBtu in 2025.

SDG&E had a slight decrease of 0.04 percent for core procurement revenue requirement from 2024 to 2025, driven by lower gas sales volume and mild winter conditions. The average procurement rate increased from $3.50/MMBtu in 2024 to $3.94/MMBtu in 2025.

Gas Transportation Costs: Transmission, Distribution, and Storage

The CPUC authorizes natural gas distribution utilities' revenue requirement for operating their extensive natural gas transmission, distribution, and storage systems safely and reliably, and for providing various customer services. These costs have steadily increased in recent years. The bulk of these revenue requirements are determined by the CPUC in the utilities' rate cases.

With the increased emphasis on safety at both the state and federal level in the aftermath of incidents including the San Bruno pipeline rupture and the Aliso Canyon natural gas storage field leak, the CPUC has authorized increased revenue requirement for all three major gas utilities with respect to transmission and distribution. Specifically, increases in total authorized revenue requirement for transmission, distribution, storage, and customer services, combined under the "transportation"[52] category, have increased by 58.16 percent from 2019 to 2025. Over the same time period, transportation revenue requirement has increased by 62.38 percent for PG&E, 52.87 percent

[52] PG&E's authorized revenue requirement for storage is included in core procurement rate category.

for SoCalGas, and 67.50 percent for SDG&E. **Table 3.4** shows historical revenue requirement for transportation from 2019 to 2025.

Table 3.4: Historical Transportation Revenue Requirement ($000)

Utility	2019	2020	2021	2022	2023	2024	2025
PG&E	3,389,751	3,531,809	3,783,288	4,224,068	3,986,325	5,144,821	5,504,213
SoCalGas	3,550,769	3,723,109	3,896,051	4,117,214	4,550,164	5,005,788	5,427,989
SDG&E	478,127	614,121	585,603	623,563	704,014	744,064	800,856
Total	**7,418,647**	**7,869,039**	**8,264,942**	**8,964,845**	**9,240,503**	**10,894,673**	**11,733,058**

Transportation represented 77.46 percent of total utility gas revenue requirement in 2025, an increase of 7.70 percent from 2024.

PG&E transportation revenue requirement increased by 6.99 percent from 2024 to 2025, primarily due to Distribution, Transmission, CPUC Fees, and Revenue Fees and Uncollectibles (RF&U) categories. The Distribution and Transmission category reflect increases authorized under the 2023 General Rate Case Decision D.23-11-069. The CPUC Fees category increased as approved in CPUC Resolution M-4874, which adopted an increase to the CPUC fee. This resulted in the CPUC rate for gas customers rising from $0.00101 to $0.00254 between 2024 and 2025.

For balancing accounts, some amounts are entered into PG&E's rate model without RF&U. In 2025, balancing account balances were more undercollected in general than in 2024, resulting in a higher RF&U amount. In addition, the uncollectibles factor increased in 2025 as authorized in AL 4989-G.

Transportation revenue requirement for SoCalGas increased by 8.43 percent from 2024 to 2025. The increase was primarily driven by the Distribution, Transmission, Distribution Integrity Management Program (DIMP), Transmission Integrity Management Program (TIMP), and Hazardous Substance Mechanism (HSM)[53] categories. The increase in the Distribution and TIMP categories is due to the implementation of the 2024 GRC Decision (D.24-12-074), effective February 2025 through AL 6430-G-A & 6430-G-B. This increased base margin and amortized undercollected balances from 2024.[54] The increase seen in the DIMP category reflects recovery of authorized undercollected balance in the DIMP Balancing Account per Resolution G-3610, effective September 1, 2025. The HSM category records the amortization of the Hazardous Substance Cost Recovery Account (HSCRA), which had a higher undercollected balance in 2025 compared to 2024.

[53] The HSM includes costs associated with hazardous substance cleanup and litigation, and related insurance recoveries as set forth in D.94-05-020.

[54] Tracked in General Rate Case Memorandum Account (GRCMA).

SDG&E transportation revenue requirement increased by 7.63 percent from 2024 to 2025, primarily driven by the Distribution, Other Balancing Accounts Balances, and GHG Program categories. The increases in the first two categories are largely attributable to the implementation of the 2024 GRC Decision (D.24-12-074). The increase in the GHG Program category reflects higher GHG costs recorded in 2025.

Gas Public Purpose Programs and other Customer Programs Costs

Several natural gas programs operated by the IOUs are under State mandates, apart from those under CPUC mandates. Among these, two large components are: (1) Greenhouse Gas Costs and Allowance Proceeds; and (2) Gas Public Purpose Program Costs,[55] discussed in detail below. Information on the applicable State Mandates (including PUC Sections) for covered programs is included in Appendix B: Historical Natural Gas Revenue Requirements.

Greenhouse Gas Compliance Costs and Allowance Proceeds

Since January 1, 2015, natural gas utilities have been covered under California's Greenhouse Gas Cap-and-Invest Program and buy compliance instruments (offsets and allowances) to account for GHG emissions associated with the combustion or oxidation of fuels they provide to customers in California. To protect customers, CARB allocates some free allowances to natural gas utilities. In 2025, utilities can use up to 25 percent of allocated allowances to reduce compliance costs in rates, with the remainder used to support the April on-bill residential Natural Gas Climate Credit as directed by the CPUC.

In 2025 the natural gas utilities collectively introduced approximately $1.25 billion in GHG costs into rates and returned approximately $971 million in allowance proceeds to customers (see **Table 3.5**). Costs are paid by nearly all customers on a per-therm basis, while benefits are directed solely towards residential ratepayers. As a result, while total gas Cap-and-Invest costs are higher than proceeds for 2025, the average IOU residential gas customer was a net beneficiary (between $3-$40, depending on the utility) of the Cap-and-Invest Program in 2025.

[55] Decision (D.)04-08-010 designated the California Energy Commission as the administrator for Gas Research, Development, and Demonstration (RD&D) Program, or Public Interest RD&D, funded through the PPP via a surcharge on IOU gas bills.

Table 3.5: 2025 Greenhouse Gas Costs and Allowance Proceeds (in $)

Utility	2025 Natural Gas GHG Revenue Requirement	2025 Natural Gas Proceeds Distributed to Customers
PG&E	434,103,019	345,869,746
SoCalGas	723,293,042	563,051,617
SDG&E	89,938,632	62,366,404
Total	**1,247,334,693**	**971,287,767**

Gas Public Purpose Program (PPP) Costs

The CPUC also authorizes costs for three main categories of gas PPPs: energy efficiency and low-income EE (LIEE), the California Alternate Rates for Energy subsidy, and the Gas Public Interest Research, Development, and Demonstration (RD&D) Program administered by the California Energy Commission (CEC). Gas PPP costs are determined in various CPUC proceedings associated with the particular type of gas PPP. Gas PPP costs have increased since 2008 but are a relatively small part of total costs.

In 2025 gas PPP revenue requirements represented 6.64 percent of the total revenue requirement. PG&E saw an increase of 17.59 percent for gas PPP revenue requirement from 2024 to 2025. SoCalGas had a decrease of 17.87 percent, and SDG&E reported an increase of 23.67 percent from 2024 to 2025. **Table 3.6** shows the historical revenue requirement for public purpose programs from 2019 to 2025.

Table 3.6: Historical Public Purpose Programs Revenue Requirement ($000)

Utility	2019	2020	2021	2022	2023	2024	2025
PG&E	262,036	182,489	277,667	320,391	381,259	399,536	469,808
SoCalGas	357,877	363,300	324,052	349,488	460,187	561,574	461,229
SDG&E	31,055	29,811	33,204	52,680	47,240	60,941	75,363
Total	**650,968**	**575,600**	**634,923**	**722,559**	**888,686**	**1,022,051**	**1,006,400**

PG&E saw an increase across all PPP revenue requirement categories in 2025. The largest driver was the EE Programs category, which accounted for a $116 million true up in the 2025 balancing account. The CARE Program also saw an increase, with the projected revenue shortfall rising from $179 million in 2024 to $209 million in 2025, driven by a higher number of eligible customers and a higher total revenue requirement. The LIEE category increased due to a shift from overcollection in 2024 to undercollection in 2025, while the Research, Development, and Demonstration and

California Department of Tax and Fee Administration (CDTFA)[56] category saw a modest increase from a slightly higher undercollected balance.

SoCalGas PPP revenue requirement decreased from 2024 to 2025, primarily due to changes in the CARE program amortization, shifting from an undercollected to an overcollected balance. A partial offset came from an increase in the Public Interest RD&D and CDTFA category, but the overall result was still a net decrease.

SDG&E reported an increase in PPP revenue requirement for 2025. The EE Programs category saw an increase in PPP revenue requirement in 2025 due to the funding of the SDREN[57] as ordered in D.24-08-003. SDG&E also had an increase in the revenue requirement in the LIEE category and decreases in the Public Interest RD&D and CDTFA and CARE Program categories because of no amortization in 2025.

[56] State Board of Equalization (BOE) has been renamed to California Department of Tax and Fee Administration (CDTFA).

[57] SDG&E is the fiscal agent to SDREN and collects funds through the PPP.

Appendix

Detailed 2025 Electric Costs ($000)

Rate Component	Federal/State Statutory Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**4,530,673**	**5,232,101**	**531,563**
General Rate Case Revenues		CPUC Decisions	1,943,653	781,542	224,633
Non-General Rate Case Revenues		CPUC Decisions, Resolutions	2,587,020	4,450,559	306,930
Transmission Total			**2,291,479**	**1,341,594**	**862,884**
Reliability Services	FERC Order 459		18,138	8,496	177
Transmission Access Charge	FERC		585,052	203,233	(333,981)
Transmission Owner Rate Case Revenues	FERC		2,540,595	1,344,347	1,226,596
Other – FERC Rate Case Revenues	FERC		(852,306)	(214,482)	(40,337)
Other					10,429
Distribution Total			**10,378,133**	**9,984,804**	**2,108,768**
General Rate Case Revenues		CPUC Decisions	10,378,133	9,984,804	2,108,768
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	**CPUC Decisions**	**(19,019)**	**(915)**	**209**
Demand Side Management and Customer Programs Total*			**581,671**	**1,535,074**	**405,696**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions			

California Solar Initiative		CPUC Decisions	(9)		
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	199,910	51,471	7,520
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,737	477,467	
Energy Efficiency (non-PUC 399.8)			71,213		(1,000)
Electricity Program Investment Charge		CPUC Decisions	67,276	76,035	16,280
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	(13,761)		17,428
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	(233,986)	115,496	6,701
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	370,291	569,241	358,767
Other		CPUC Decisions, Resolutions		245,364	
Other Regulatory Total*			**924,556**	**893,710**	**287,218**
Catastrophic Events (CEMA)	PUC Section 454.9(a)	CPUC Decisions	364,728	17,896	
Hazardous Substance Mechanism		CPUC Decisions	41,390		94
CPUC Fee[58]	PUC Section 431	CPUC Resolution M-4816	61,836	63,308	
Other		CPUC Decisions,	456,602	812,507	287,124

[58] CPUC fees are not part of SDG&E's billed rate and instead are a separate surcharge, called the State Regulatory Fee, included on customer bills, similar to the California Energy Commission (CEC) Fee, called the State Surcharge Tax. The Total Revenue Requirement only reflects items that are included in SDG&E's billed rates.

		Resolutions			
DWR Power Charge Revenues	**AB1X, Water Code, Division 27**	**CPUC Decisions**	**2,958**		
Wildfire Fund NBC	**AB 1054**	**CPUC Decisions**	**412,562**	**416,803**	**-**[59]
Ongoing Competition Transition Charge	**AB 57, PUC Section 367(a) & 369**	**CPUC Decisions**	**(24,119)**		**5,591**
Energy Recovery Bonds (PG&E only)	**SB 772, PUC Section 848-848.7**	**CPUC Decisions, Resolutions**	**699**		
Franchise Fee Surcharge**	**PUC Sections 6350-6354, 6231**	**CPUC Decisions**			**117,233**
Electric Total			**19,079,593**	**19,403,170**	**4,308,733**
*Some costs recovered in distribution rate component					
**Not reported elsewhere.					

[59] SDG&E's costs for the Wildfire Fund NBC are included in the "Other" sub-row of the "Other Regulatory Total" section, above.

Detailed 2025 Natural Gas Costs ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SoCalGas	SDG&E
Core Procurement Total			**1,018,832**	**1,219,143**	**169,808**
Core Gas Supply Portfolio		CPUC Decisions	502,727	1,210,769	169,808
Other		CPUC Decisions	464,825	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	51,280	0	0
Incentive Mechanism		Report	0	8,374	0
Transportation Total			**5,504,213**	**5,427,989**	**800,856**
Distribution		CPUC Decisions	3,072,560	3,268,077	606,147
Gas Pipeline Integrity Management and Safety - Distribution Integrity Management Program (DIMP)				86,946	-2,869
Pipeline Safety Enhancement Plan (PSEP)			0	93,651	23,689
SoCalGas Only - Storage Integrity Management Program (SIMP)				14,041	
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,920,166	431,517	
Gas Pipeline Integrity Management and Safety -				185,628	11,502

Transmission Integrity Management Program (TIMP)					
Pipeline Safety Enhancement Plan (PSEP)				122,539	-884
Advanced Metering Infrastructure (AMI)		Report	0	284	0
Smart Meter			0	0	0
Self Gen Inc Program (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	0	0	0
Climate Smart			0	0	0
California Solar Initiative (CSI)		CPUC Decisions	5,261	2,681	151
Annual Earning Assessment (AEAP)		CPUC Decisions	-18	-226	0
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	80,221	0
Hazardous Substance Mechanism (HSM)		CPUC Decisions	95,402	7,081	421
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions	0	0	0
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions	0	0	0
Non-Public Interest Research, Development & Demonstration (RD&D)		CPUC Decisions	0	18,682	0
Core Pricing Flexibility Program		CPUC Decisions	0	23	0
Noncore Competitive Load		CPUC Decisions	0	966	0

Growth Program					
Catastrophic Event Memorandum Account (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	5,662	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accounts Balances		Report	286,594	344,090	66,695
CPUC Fee	PUC Section 431	Resolution M-4816	11,329	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	12,338	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	6,364	26,487	4,012
AB 32 Cap-And-Trade Program			2,501	16,403	1,929
Greenhouse Gas (GHG) Program		CPUC Decisions	91,716	723,236	90,063
Public Purpose Program Surcharges Total			**469,808**	**461,229**	**75,363**
Energy Efficiency (EE) Programs	PUC Sections 399.8, 890-900	CPUC Decisions	147,529	166,376	39,912
Low Income Energy Efficiency (LIEE)	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	85,631	109,266	14,341
Public Interest RD&D and California Department of Tax and Fee Administration (CDTFA)	PUC Sections 740, 890-900	CPUC Decisions	11,838	13,370	1,276
California Alternate Rates for Energy (CARE) Program	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	224,810	172,217	19,834
Port Energy Management Plan (PEMP)	PUC Section 739.1	CPUC Decisions			0

School Energy Efficiency Stimulus (SEES) Program	AB 841	CPUC Decisions			0
Statewide Energy Efficiency (SWEE) Program		CPUC Decisions			280
Gas Total			**6,992,853**	**7,108,361**	**1,046,027**