2021 CALIFORNIA ELECTRIC AND GAS UTILITY COSTS REPORT

AB 67 Annual Report to the Governor and Legislature

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California Public Utilities Commission

A digital copy of this report can be found at:

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Executive Summary

The California Public Utilities Commission (CPUC) issues the Assembly Bill (AB) 67 Annual Report (referred to as the 2021 California Electric and Gas Utility Costs Report) pursuant to California Public Utilities Code Section 913, which requires the CPUC to publish the costs to ratepayers of all utility programs and activities currently recovered in retail rates.[1]

The 2021 California Electric and Gas Utility Costs Report, published in 2022, provides a detailed narrative and transparency into factors driving electric and gas rates for 2021 activities.

Key electric highlights from this report include:

- Compared to 2020, the 2021 CPUC-authorized annual revenue requirement for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) increased by 6.2 percent, 18.8 percent, and 0.4 percent, respectively.
    - Compared to 2020, the 2021 generation costs decreased for PG&E, SCE, and SDG&E by 8.0 percent, 4.9 percent, and 6.3 percent, respectively. The decreases were driven by customer departures to Customer Choice Aggregators, which reduced the number of utility bundled customers. Due to fixed costs and high prices per megawatt hour, generation costs rose on a per customer basis for those remaining on bundled service.
    - During the same time period, distribution costs increased for PG&E and SCE by 6.1 percent and 33.4 percent, respectively, and decreased for SDG&E by 5.6 percent. Electric generation and distribution are the largest components of electric rates, and collectively account for approximately 75 percent of the utilities' electric rates.
- Compared to 2020, the 2021 transmission costs decreased for PG&E by 17.6 percent and increased for SCE and SDG&E by 32.0 percent and 31.7 percent, respectively.
- In Federal Energy Regulatory Commission (FERC) proceedings for transmission owner (TO) rate cases from 2008 to 2021, the CPUC has successfully negotiated a reduction to the transmission revenue requirements resulting in a cumulative savings of approximately $2.8 billion for California ratepayers.

[1] Section 913 reporting requirements apply to electrical corporations with at least 1,000,000 retail customers in California and gas corporations with at least 500,000 retail customers in California.

- In 2021, the electric California investor-owned utilities collectively included approximately $173 million in direct greenhouse gas Cap-and-Trade Program costs in rates but provided ratepayers approximately $773 million in credits from sale of California Air Resources Board (CARB)-allocated carbon allowances at auction.
- In 2021, Demand-Side Management program[2] costs, when combined, accounted for three percent of the total electric revenue requirement for the four large IOUs in California (PG&E, SCE, SDG&E, and Southern California Gas Company (SoCalGas)).
- Regulatory fees[3] in 2021 totaled approximately $780 million and accounted for roughly five percent of the annual revenue requirement for the electric IOUs (PG&E, SCE, and SDG&E).
- Increases in total system average rates generally tracked inflation for PG&E and SCE. SDG&E's average rates have been above the Consumer Price Index since 2009.

Key gas highlights from this report include:

- Compared to 2020, the 2021 total natural gas utility costs increased by 10.8 percent. The increase in natural gas resulted from a substantial increase in core[4] procurement costs along with smaller increases in both transportation and Public Purchase Programs (PPP) costs. The combination of Polar vortex cold weather and pipeline outages, which created deliverability concerns and supply reductions, caused price spikes in the winter months.

[2] Demand-Side Management programs include programs such as Energy Efficiency, Energy Savings Assistance, California Alternative Rates for Energy (administrative costs only), Self-Generation Incentive Program, Demand Response, and Electric Program investment Charge.

[3] Regulatory fees include a variety of charges levied by federal, state, and local governments.

[4] The typical natural gas utility customers in California are residential and small commercial customers, referred to as "core" customers.

I. Introduction

Enacted as AB 67 in 2005, California Public Utilities Code 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.

The report is to be submitted to the Governor and the Legislature by April 1st of each year and is required to include the following:

1. Each program mandated by statute and its annual cost to ratepayers.
2. Each program mandated by the CPUC and its annual cost to ratepayers.
3. Energy purchase contract costs and bond-related costs incurred pursuant to Division 27 of the Water Code (commonly known as Department of Water Resources (DWR) related costs).
4. All other aggregated categories of costs currently recovered in retail rates as determined by the CPUC.

This 2021 California Electric and Gas Utility Costs Report is submitted by the CPUC to fulfill these statutory requirements.

Background

The cost structures and the rate-setting process for California's utilities are inherently complex and can be difficult to track over time. To help create more transparency in the rate-setting process, the California Legislature passed AB 67 in 2005. AB 67 establishes an annual reporting requirement to identify the costs to ratepayers of all utility programs and activities currently recovered in retail rates. As in previous years, this report provides a detailed narrative of various energy policies in California, along with a breakdown of the underlying costs that drive electric and gas rates, including charts and tables showing how these costs and rates have varied since 2011.

The report presents an analysis of the CPUC-authorized revenue requirements for the four major California investor-owned utilities (IOUs or utilities): PG&E, SCE, SDG&E, and SoCalGas. Using sales forecasts, rates are set to collect these authorized revenue requirements. For certain utility programs, discrepancies between authorized revenue requirements and actual revenues and expenses are captured through balancing account mechanisms, which true-up the actual revenue to the authorized revenue requirement in the following year. This mitigates the risk of the utilities collecting more than or less than their authorized revenue requirements, particularly if sales are lower than forecast due to conservation, behind-the-meter solar, and efficiency programs.

Overview

Electric Utility Costs

- **Compared to 2020, the CPUC-authorized annual revenue requirements[5] for PG&E, SCE, and SDG&E increased by 6.2 percent, 18.8 percent, and 0.4 percent, respectively.** The 2021 revenue requirement for the three electric utilities are shown in **Table 1.1**. The total company revenue requirement (including transmission)[6] for the electric utilities in 2021 is as follows: PG&E $14.4 billion, SCE $14.4 billion, and SDG&E $4.3 billion for a total of $33.1 billion.

Table 1.1: Electric Utility Revenue Requirement Comparison ($000)[7]

Utility	2021 CPUC	2020 CPUC	Difference ($000)	Difference %	2021 Transmission	2021 Total Company
PG&E	12,349,288	11,624,239	725,049	6.2	2,035,538	14,384,826
SCE	13,141,517	11,059,550	2,081,967	18.8	1,253,026	14,394,543
SDG&E	3,598,631	3,582,913	15,718	0.4	736,175	4,334,806
Total	**29,089,436**	**26,266,702**	**2,822,734**	**10.8**	**4,024,739**	**33,114,175**

Much of the increase in PG&E's, SCE's, and SDG&E's revenue requirements are due to increased distribution related general rate case (GRC) costs.[8]

- **Power procurement costs decreased for PG&E, SCE, and SDG&E during 2021.** Power procurement costs include the costs of generating and purchasing electricity as well as capital costs related to those items. **Table 1.2** shows the 2021 revenue requirement for the three electric utilities associated with generating and procuring electricity.

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[5] All references to revenue requirements are to the CPUC-authorized annual revenue requirement and are in current dollars (not adjusted for inflation) unless otherwise indicated.

[6] The Federal Energy Regulatory Commission has jurisdiction over transmission-related revenue requirements.

[7] PG&E Advice Letter 6265-E/E-A, SCE Advice Letter 4590-E, and SDG&E Advice Letter 3696-E-B, effective 8/1/2021, 10/1/2021, and 3/1/2021.

[8] See Chapter II for a discussion on general rate cases revenue requirements.

Table 1.2: Electric Generation Revenue Requirement Comparison ($000)

Utility	2021	2020	Difference	
			$000	%
PG&E	5,073,429	5,513,712	(440,283)	(8.0)
SCE	5,237,899	5,508,750	(270,851)	(4.9)
SDG&E	1,427,182	1,523,136	(95,954)	(6.3)
Total	**11,738,510**	**12,545,597**	**(807,088)**	**(6.4)**

The decrease in PG&E's, SCE's, and SDG&E's generation revenue requirement from 2020 to 2021 is due to a growing percentage of the IOUs' load moving to service from Customer Choice Aggregators (CCAs), reducing the total load for which the IOUs must procure. In 2021, 35 percent of total IOU system load was served by CCAs. However, due to high fixed costs and high prices per megawatt hour for those customers remaining with service from the utility in 2021, generation rates rose on a per customer basis.

For additional analysis, see Chapter IV.

- **Electric distribution costs increased for PG&E and SCE, and decreased for SDG&E.** Distribution costs include the costs of providing service below a certain voltage (60 kilovolt (kV), 200 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are regulated by the CPUC. **Table 1.3** shows the 2021 revenue requirement for the three electric utilities associated with distribution of energy through the electric grid.

Table 1.3: Electric Distribution Revenue Requirement Comparison ($000)

Utility	2021	2020	Difference	
			$000	%
PG&E	5,595,486	5,273,802	321,684	6.1
SCE	6,587,686	4,939,144	1,648,543	33.4
SDG&E	1,599,694	1,694,297	(94,602)	(5.6)
Total	**13,782,867**	**11,907,242**	**1,875,624**	**15.8**

PG&E's and SCE's increase can be attributed to an increase in distribution related GRC expenses approved in the 2020 PG&E GRC and the 2021 SCE GRC, respectively. SDG&E's decrease can be attributed to less distribution related GRC expenditures in 2021 than were approved in the 2019 GRC; however, spending in the GRC cycle does not occur at a constant rate. SDG&E overcollected funds for distribution spending in rates from their customers in 2020, but had not yet spent the money. Therefore, 2021 SDG&E distribution rates reflect a refund of this overcollection. For additional analysis, see Chapter III.

- **Compared to 2020, electric transmission costs passed onto ratepayers decreased overall for PG&E and increased for SCE and SDG&E.** Transmission costs include the costs of providing service above a certain voltage (60 kV, 200 kV, and 69 kV for PG&E, SCE, and SDG&E, respectively) that are part of the electric grid controlled by the California Independent System Operator (CAISO) and regulated by the FERC. **Table 1.4** shows the 2021 costs for the three electric utilities associated with transmission of energy through the electric grid.

Table 1.4: Electric Transmission Cost Comparison ($000)

Utility	2021	2020	Difference	
			$000	%
PG&E	2,035,538	2,469,714	(434,176)	(17.6)
SCE	1,253,026	949,095	303,931	32.0
SDG&E	736,175	559,089	177,086	31.7
Total	**4,024,739**	**3,977,898**	**46,841**	**1.2**

PG&E's overall decrease in transmission costs to ratepayers between 2020 and 2021 is related to two downward adjustments for overcollection in prior years. The decrease reflects the true-up of overcollection in 2019 from a FERC rate case settlement beneficial to ratepayers effectuated at the end of 2020. More significantly, there was an adjustment related to substantial overcollection from ratepayers in a balancing account related to the costs paid to, and revenue received from, the CAISO for high voltage transmission in 2019 and 2020. While the costs of transmission continue to increase, the true-up from the rate case coupled with the adjustment to the balancing account resulted in the anomalous decrease in costs to ratepayers of over $400 million in 2021.[9] A much smaller reduction in costs relates to a decrease in the revenues collected as part of its transmission owner rate case at FERC.[10] SDG&E's increase is related to: 1) higher Operating and Maintenance (O&M), Administrative and General (A&G) and depreciation expenses, and 2) an increase in rate base and return on investment.[11] SCE's increase in transmission costs relates to a large upward adjustment to the SCE 2017/2018 wildfires/mudslides reserve and a large formula true-up adjustment due to 2020 under-collections.[12] For additional analysis, see Chapter III.

[9] The transmission costs in Table 1.4 represent the sum of the Transmission Revenue Requirement in PG&E's transmission owner rate case at FERC and costs or credits from transmission-related balancing accounts. The greatest contributor to PG&E's decrease from 2020 to 2021 relates to the Transmission Access Charge Balancing Account (TACBA) Adjustment, which is a mechanism to make a transmission owner whole in what it pays to the CAISO for use of the high voltage grid and the collection of revenues from the CAISO as an owner of assets on the transmission grid. A substantial net overcollection in years 2019 and 2020 in the TACBA resulted in a reduction in transmission costs of over $430 million in 2021.

[10] It is worth noting that as a result of the settlement in PG&E's TO20 rate case, which was filed at FERC on October 15, 2020, costs to PG&E's ratepayers related to that rate case were reduced by an estimated $250 to $300 million in 2020 and nearly $600 million in 2021. Annual savings related to the Settlement will continue through the term of the TO20 Formula rate, which ends in 2023.

[11] SDG&E's TO5 Cycle 4 Formula Rate Filing, TO5-Cycle 4, Transmittal Letter, December 1, 2021.

[12] This year's rate case (SCE TO2020) is an Annual Informational Rate Case Filing as required by the FERC settlement in SCE TO2019A, FERC Docket ER19-1553.

- **Public Purpose Program costs increased for PG&E and SCE, and decreased for SDG&E, since 2020.** These Public Purpose Programs (PPPs) include Energy Efficiency, Energy Savings Assistance, and California Alternative Rates for Energy (CARE) among other programs like the Schools Energy Efficiency Program (SEEP), created pursuant to AB 841. The primary driver of the increase in PPP costs from 2020-2021 include a significant increase in CARE collections. **Table 1.5** shows the 2020 and 2021 revenue requirement for the three electric utilities associated with PPPs.

Table 1.5: Electric PPP Revenue Requirement Comparison ($000)

Utility	2021	2020	Difference	
			$000	%
PG&E	467,964	315,820	152,144	48.2
SCE	426,011	223,435	202,576	90.7
SDG&E	265,797	297,507	(31,710)	(10.7)
Total	**1,159,772**	**836,762**	**323,010**	**38.6**

- **Bonds and Regulatory Fees (including nuclear decommissioning revenue requirements) increased for PG&E, SCE, and SDG&E during 2021.** During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. These bonds were retired in September 2020. Beginning October 1, 2020, the related revenue requirements have been substantively replaced by charges to support the AB 1054 Wildfire Fund. Fees include a variety of charges levied by federal, state, and local governments. Fees are included as specific components of other revenue requirements, except for nuclear decommissioning costs, which are recovered by the Nuclear Decommissioning Adjustment Mechanism (NDAM). **Table 1.6** shows the 2021 revenue requirements for the three electric utilities associated with bonds and nuclear decommissioning activities.

Table 1.6: Bonds and Fees Revenue Requirement Comparison ($000)

Utility	2021	2020	Difference	
			$000	%
PG&E	1,054,517	520,905	533,612	102.4
SCE	555,534	388,221	167,313	43.1
SDG&E	95,985	67,974	28,012	41.2
Total	**1,706,037**	**977,100**	**728,937**	**74.6**

During 2021, much of the variation in the revenue requirements for bonds and assorted fees was driven by the Wildfire Fund Non-Bypassable Charge. For additional analysis, see Chapter VI.

- **The revenue requirements for PG&E, SCE, and SDG&E increased in 2021 due to adjustments for amortizations of balances in balancing and/or memorandum accounts. Table 1.7** shows the effects of these adjustments on the revenue requirements for the electric utilities.

Table 1.7: Adjustments to the 2021 Revenue Requirement ($000)

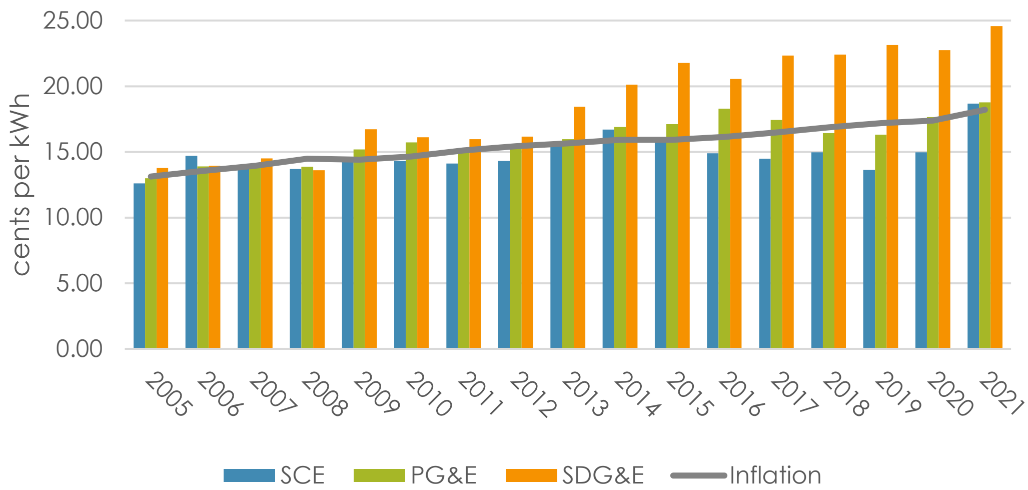
Utility	Forecasted 2021 Costs	Amortization Adjustments	Authorized 2021 Revenue Requirement	Difference %
PG&E	11,622,521	726,767	12,349,288	6.3%
SCE	12,136,289	1,005,228	13,141,517	8.3%
SDG&E	3,186,361	412,269	3,598,631	12.9%
Total	**26,945,172**	**2,144,264**	**29,089,436**	**8.0%**

Utilities add amortizations of balancing and/or memorandum accounts to the annual revenue requirement to recover costs of prior years and set rates incorporating this adjustment. The information in this report refers to the adjusted annual revenue requirement to show the annual cost to ratepayers.

- **Increases in System Average Rates generally tracked inflation, except for SDG&E. SDG&E's average rates have been above the Consumer Price Index (CPI) since 2009 (Figure 1.1).** From 2017 to 2021, system average rates across the three electric IOUs have increased at an annual average of approximately 3.9 percent (**Table 1.8**), which is above the average annual inflation rate of 2.5 percent over the same time period. In 2021, SCE's system average rate was 18.68 cents per kilowatt hour (¢/kWh), PG&E's was 18.78 ¢/kWh, and SDG&E's was 24.58 ¢/kWh.[13] To show the effect of inflation from 2005 – 2021, the average of all three utilities' system average rates in 2005, adjusted for inflation to 2021 nominal dollars, is 18.21 ¢/kWh. The average of all three utilities' system average rates for 2021 is 20.68 ¢/kWh, which suggests that the cost of electricity to the ratepayer generally increased by 2.47 ¢/kWh since 2005 when excluding the effects of inflation.

[13] PG&E Advice Letter 6265-E/E-A, SCE Advice Letter 4590-E, and SDG&E Advice Letter 3696-E-B, effective 8/1/2021, 10/1/2021, and 3/1/2021, respectively.

Figure 1.1: Trends in Electric Total System Average Rates (2005-2021)[14]



Annual Inflation Rate (2012-2021)[15]										
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Average (2017-2021)
2.1%	1.5%	1.6%	0.1%	1.3%	2.1%	2.4%	1.8%	1.2%	4.7%	**2.5%**

Table 1.8: Annual Change in Electric Total System Average Rates (2017-2021)

Utility	2017	2018		2019		2020		2021		Average
	Rate	Rate	% Change	Rate	% Change	Rate	% Change	Rate	% Change	% Change
SCE	14.48	14.96	3.3	13.62	(8.9)	14.97	9.9	18.68	24.8	7.3
PG&E	17.42	16.43	(5.7)	16.30	(0.8)	17.65	8.3	18.78	6.4	2.0
SDG&E	22.32	22.40	0.3	23.13	3.3	22.75	(1.7)	24.58	8.1	2.5

- **For SDG&E, system average rates have generally trended above inflation since 2009.** All three utilities have experienced declines in kWh sales, which also lead to increased system average rates when the revenue requirement remains flat or rises. The increase in average rates for PG&E, SCE, and SDG&E in 2021 is due to an increase in distribution costs.

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[14] Total System Average Rates reflect total authorized revenue requirement and total forecasted sales for both bundled and unbundled customers.

[15] Source: Bureau of Labor Statistics, CPI-All Urban Consumers.

- **Electric generation and distribution are the largest components of electric rates.** As shown in **Figure 1.2** and **Table 1.9**, utility-owned generation and purchased power sources, plus distribution, collectively account for approximately 75 percent of the utilities' electric rates.

Figure 1.2: 2021 System Average Electric Rate Components

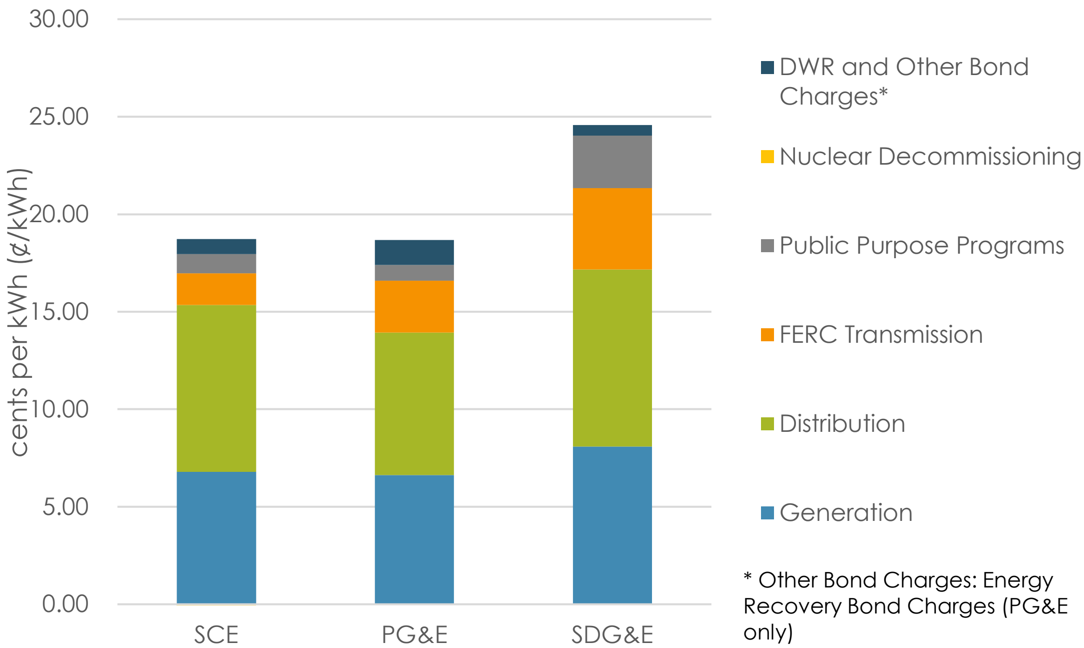


Table 1.9: 2021 System Average Electric Rate Component Values (¢/kWh)

Rate Component	SCE[16]	PG&E	SDG&E
Generation	6.80	6.62	8.09
Distribution	8.55	7.30	9.07
FERC Transmission	1.63	2.66	4.17
Public Purpose Program	0.99	0.82	2.70
Nuclear Decommissioning	(0.06)	0.10	0.01
DWR and Other Bond Charges	0.78	1.27	0.54
Total	**18.68**	**18.78**	**24.58**

[16] The negative value for nuclear decommissioning rate component for SCE is associated with the overcollection of revenue. These overcollections were returned to ratepayers in 2021.

Gas Utility Costs

- **For 2021, total natural gas utility costs increased by 10.8 percent from 2020 compared to the 0.3 percent decrease from 2019 to 2020, the 12.8 percent increase for 2018 to 2019, and the 2.7 percent decrease from 2017 to 2018**. The increase in the 2021 gas utility revenue requirement is a result of a substantial increase in core procurement costs as well as smaller increases in transportation and Public Purpose Program (PPP) costs. The core procurement cost increase is due to a rise in natural gas commodity prices. Gas supply costs have gone up nationwide and globally, while cold winter weather and reduced interstate pipeline capacity have also contributed to the increased commodity prices. Please see Chapter VII for a discussion of gas utility costs.

The remainder of this report provides a breakdown of the various electric and natural gas revenue requirement components and identifies the sources of the greatest increases in costs. Chapters II through VI address electric revenue requirements and Chapter VII addresses natural gas revenue requirements. In addition to the detailed summary tables provided throughout the text, Appendix A and Appendix B provide summaries of each IOU's authorized revenue requirements organized by the rate components typically shown on customer bills.

II. Determining Revenue Requirements

Due to the increasingly varied nature of utility costs and the multitude of energy policy programs, the determination of the funds needed for utility service and the rate-setting process at the CPUC have grown more complex over time. The following venues are used to determine the revenues that the utilities are authorized to collect through rates:

1. **General Rate Cases (GRCs):** GRCs for the large energy utilities occurred on a three-year cycle at the CPUC in the past; however, utilities are transitioning to a four-year cycle based on Decision (D.) 20-01-002. In GRCs, the CPUC evaluates the regulated operations of the utilities and determines the reasonableness of utility requests for changes in revenue needed to fund utility service. For PG&E, SCE, and SDG&E, the GRCs are divided into two phases. Phase I of a GRC determines the total amount the utility is authorized to collect (also called the "revenue requirement"), while Phase II determines the share of the utility's total cost each customer class is responsible and the rate schedules for each class.
2. **Transmission rate cases at the Federal Energy Regulatory Commission (FERC):** The CPUC is required to allow recovery of all FERC-authorized costs. Because transmission rates are subject to oversight by FERC, the transmission revenue requirements of the various utilities that participate in the CAISO are determined in FERC proceedings, called Transmission Owner (TO) rate cases.
3. **Energy Resource Recovery Account (ERRA) proceedings**: The CPUC annually reviews each utility's fuel and power purchase forecast and, to the extent deemed reasonable, passes through those costs without any profit or mark-up for the utility. Some public purpose charges are also authorized here.
4. **Program Budget allocations**: Specific program area proceedings in which program budgets are determined.

The utilities earn a rate of return (authorized profit from rate base) on utility-owned and capitalized assets and equipment. For many cost categories, such as purchased power and fuel, there is no rate of return or profit – the utilities are only reimbursed for these costs from customers as "pass-through" costs.

Categorization of Utility Costs

Utility costs or revenue requirements fall into three major categories: generation, distribution, and transmission. While this basic categorization of costs reflects major areas of utility operations or business units, it is also used to determine what portions of utility costs should be paid by different types of customers. For instance, some customers do not receive full service (also known as "bundled service") from the utility and may generate their own electricity on site or buy electricity from a non-utility source (e.g., an Electric Service Provider (ESP), or a Community Choice Aggregator (CCA)). Customers who receive electricity from a CCA or ESP do not typically pay generation costs but do pay transmission and distribution costs. However, these customers are also required to pay non-bypassable charges for generation procured on their behalf before they departed from bundled service. Additionally, some larger customers receive service at transmission voltage levels and are not charged for use of the utility distribution system. **Table 2.1** offers a breakdown of the major components of the electric IOUs' 2021 revenue requirements.

Table 2.1: 2021 Electric IOU Authorized Revenue Requirements ($000)

Revenue Component	SCE	PG&E	SDG&E
Generation / Energy Procurement	5,237,899	5,073,429	1,427,182
Purchased Power	4,437,318	2,639,122	1,124,691
Utility Owned Generation	86,745	358,334	201,568
General Rate Case	697,827	2,075,071	183,152
Other Regulatory	16,009	901	(82,229)
Distribution	6,587,686	5,595,486	1,599,694
Transmission	1,253,026	2,035,538	736,175
Public Purpose Programs	760,397	625,857	475,769
Bonds and Fees	555,534	1,054,517	95,985
Total 2021 Revenue Requirement	**14,394,543**	**14,384,826**	**4,334,806**

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). This ROR is the main source of profit for regulated utilities. Other things being equal, a larger rate base results in a higher net profit for the utilities.

Depreciation causes the utilities' rate bases for existing assets to decline over the useful life of the assets, while building new plants or making capital improvements to existing plants causes their rate bases to increase. Changes in rate base also result in changes in the depreciation expense allowance utilities are authorized to collect. As shown in **Figure 2.1** below, the result of these competing effects has historically been a net increase in rate base. **Figure 2.1** indicates that between 2011 and 2021, the utilities' rate bases doubled in size from $39.2 billion to $78.3 billion, or a 100 percent increase in nominal dollars over the past decade, triggering corresponding increases in GRC revenue requirements.[17]

[17] When adjusted for inflation, the 2011 rate base equals $46.5 billion. Therefore, an inflation-adjusted comparison of rate base from 2011 to 2021 indicates the rate base increased in size from $46.5 billion (adjusted for inflation from $39.2 billion) to $78.3 billion, or 68 percent.

Figure 2.1: Trends in Electric Utility Rate Base

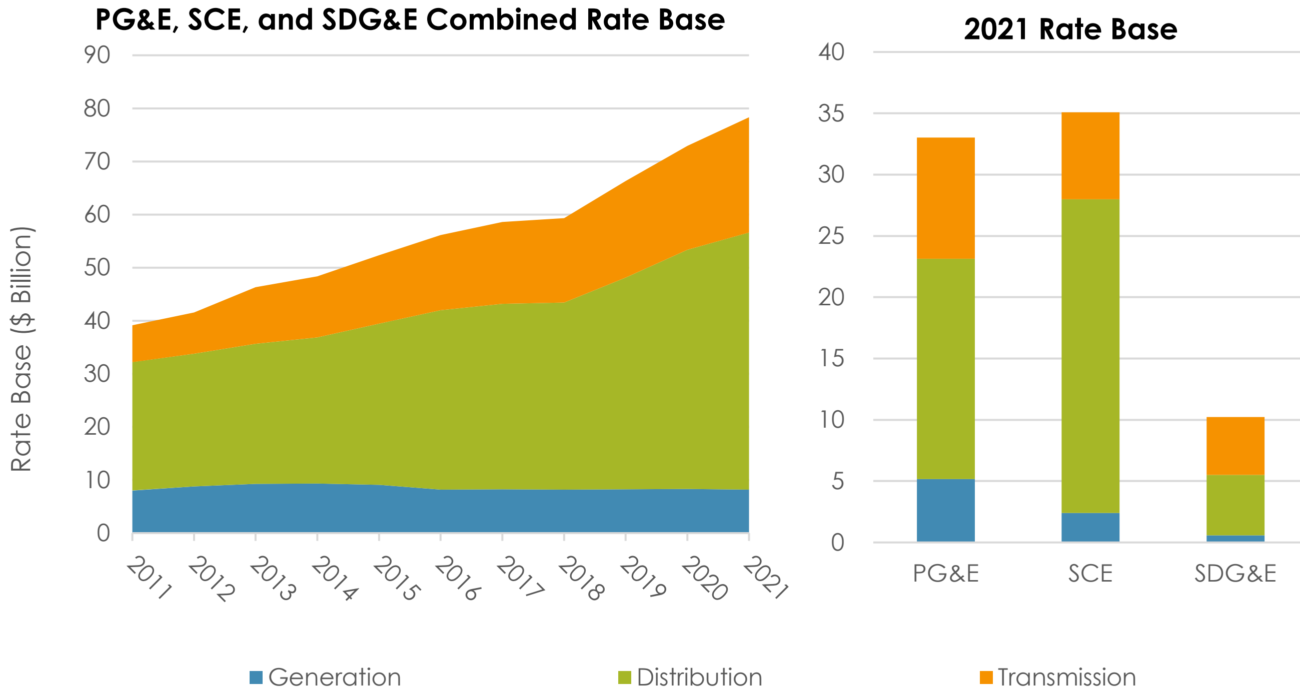


Table 2.2 shows the contributions of generation, transmission, and distribution components to the 2021 rate base.

Table 2.2: 2021 Utility Rate Base Components ($000)

Category	PG&E	SCE	SDG&E	Total
Generation	5,180,182	2,403,434	580,787	
Distribution	17,958,395	25,578,835	4,923,675	
Transmission	9,886,373	7,098,630	4,718,604	
Total All IOUs	**33,024,950**	**35,080,899**	**10,223,066**	**78,328,915**

III. General Rate Case Revenue Requirements

Costs that utilities can forecast with reasonable accuracy are examined and approved by the CPUC in general rate case (GRC) proceedings. In January 2020, the major utilities were directed by the CPUC to take procedural steps to transition from a three-year GRC cycle to a four-year GRC cycle.[18] In these GRC proceedings, the CPUC sets a pre-specified revenue requirement for the first year in the cycle, or "test year," with formulaic adjustments for the subsequent "attrition years" until the next GRC cycle commences.

The utilities' authorized revenue requirements typically remain unchanged even if the utilities spend more or less than authorized by the CPUC. The exception to this occurs in operations covered by balancing and/or memorandum accounts which can adjust the authorized revenue requirement based on actual spending upon CPUC approval.

Approximately 63 percent of the utilities' electric revenue requirements are set in GRCs at the CPUC and the FERC (FERC sets the revenue requirement for transmission assets), while the remaining 37 percent consists of pass-through of the costs of power procurement, DWR bond charges, nuclear decommissioning trusts, Public Purpose Programs, fees, and regulatory expenses approved by the CPUC.

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: O&M, Depreciation, Return on Rate Base, and Taxes. **Table 3.1** below summarizes the total CPUC-jurisdictional GRC revenue requirements as broken down into these cost categories for the three electric utilities, followed by detailed descriptions of each.

[18] The CPUC adopted a revised general rate case filing schedule to be applied to all future GRC applications, effective June 30, 2020. Because the utilities were in various stages of their current GRCs, they were directed to take procedural steps to implement the transition to the four-year GRC cycle. Source: CPUC Decision 20-01-002, January 22, 2020, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M325/K471/325471063.PDF.

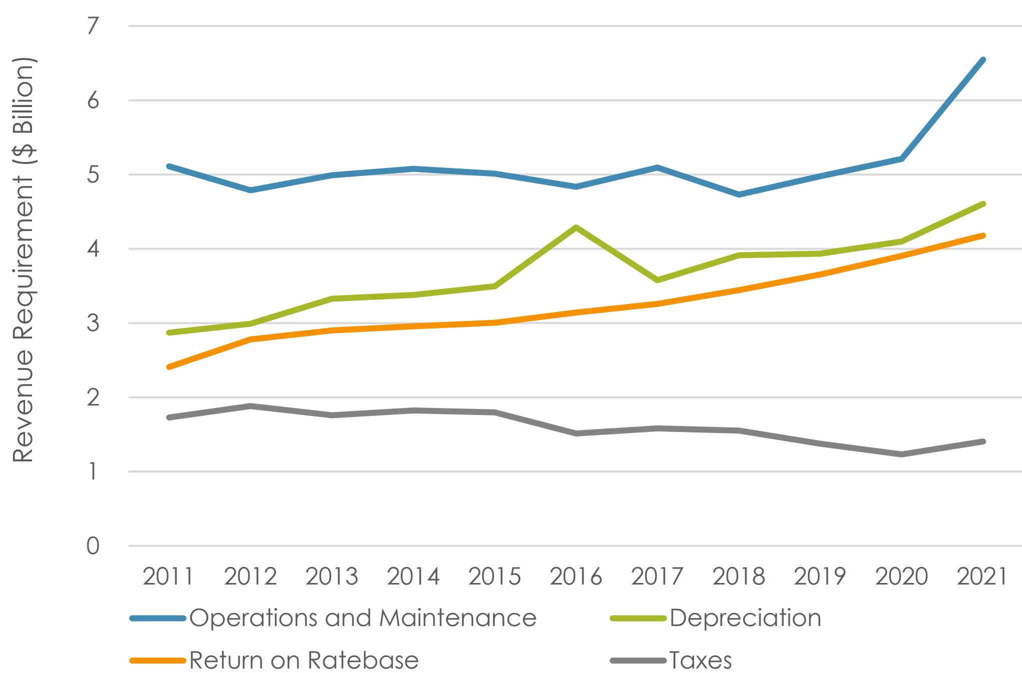
Table 3.1: 2021 General Rate Case Revenue Requirements ($000)[19]

	PG&E	SCE	SDG&E
Operation and Maintenance	3,173,465	2,552,056	822,763
Depreciation	2,282,218	1,902,940	420,271
Return on Rate Base	1,663,954	2,159,206	355,347
Taxes	550,920	671,312	184,466
Total	**7,670,557**	**7,285,513**	**1,782,847**

(Excludes FERC-determined transmission revenue requirements)

Figure 3.1 below shows a ten-year trend of the costs for O&M, Depreciation, Return on Rate Base, and Taxes for the utilities.

Figure 3.1: Trends in General Rate Case Revenue Requirement[20]



- **<u>Operations and Maintenance (O&M)</u>:** These costs include all labor and non-labor expenses for a utility's operation and maintenance of its generation plants and distribution system. While the utilities are required to maintain their systems in accordance with safety and reliability standards and industry best practices, the CPUC does not typically dictate how the utilities spend O&M funds. Depending on how the utilities manage various projects, they may spend more or less than the CPUC authorized O&M budget.

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[19] 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.

[20] Values shown are for Distribution and Generation Revenue Requirement.

To better assess utility spending on ensuring the safe operation of their systems, the CPUC adopted a framework for incorporating risk-based decision-making into GRCs in 2014. This risk-based decision-making framework involves two key components: the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, and a Risk Assessment Mitigation Phase (RAMP) for each large energy utility one year in advance of its GRC proceeding.

In 2015, the S-MAP applications of the major electric and gas utilities were consolidated, and the utilities and parties discussed the methods by which to assess the risks in their operations. In 2020, a second S-MAP was opened to enhance the RAMP process. Each utility's RAMP proceeding utilizes the reporting format developed in the S-MAP proceeding and describes how the utility plans to assess and mitigate its risks. SDG&E and SoCalGas were the first utilities to initiate the RAMP, in October 2016, followed by PG&E in November 2017, and SCE in November 2018.[21] In June 2020, PG&E submitted its 2020 RAMP. SDG&E and SoCalGas submitted a succeeding RAMP in May 2021. In the general rate cases, the CPUC undertakes a thorough review of O&M costs, separately, for generation and distribution related facilities, and for general plant. Beginning in Test Year 2019, the CPUC incorporated RAMP findings into the utilities' GRC decisions.

- **Depreciation:** Capital investments in facilities and assets are initially financed by the utilities' own funding sources and are returned to the utilities with ratepayer funding in the form of a depreciation allowance. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.

- **Rate of Return on Rate Base:** Because the utilities provide the upfront financing for all capitalized expenditures, the CPUC authorizes a rate of return (ROR) on the invested capital. The ROR is the weighted average cost of debt and shareholder equity, and the CPUC allows the opportunity to earn a fair and reasonable return sufficient to allow the utilities to obtain financing. Formerly determined in each utility's GRC, the ROR is now determined in a separate cost of capital proceeding for the major IOUs. The utilities' actual ROR may be more, or less, than what is authorized by the CPUC, depending on how well the utilities manage their operations and costs. In most instances, if the utilities keep costs below their authorized revenues, actual ROR will exceed the authorized level. GRC ratemaking is aimed at providing the utilities with an incentive to stay within approved, pre-specified budgets. Under this ratemaking treatment, utility profits decline if spending is higher than the GRC authorized revenue requirement, and vice versa.

The utilities do not earn a return on purchased power and fuel expenditures, which, as noted elsewhere in this report, are pass-through costs reviewed in Energy Resource Recovery Account (ERRA) proceedings.

[21] SCE's next RAMP is anticipted to be submitted during the second quarter of 2022.

The CPUC also requires the utility to track some costs in "one-way balancing accounts." For expense categories tracked in one-way balancing accounts, if the utility underspends, then the utility returns the funds to ratepayers. If a utility overspends, in a one-way balancing account, the utility has to absorb the costs in profits. One-way balancing accounts are occasionally used for spending related to safety such that the utility does not profit from underspending in those areas.[22]

Distribution Revenue Requirement

Since 2011, the total distribution revenue requirement has increased, from $8.79 billion to $13.78 billion (**Figure 3.2**).[23] Over the same time period, depreciation expenses have experienced the greatest increase, with an approximate 3.2 percent average annual growth rate.[24] The increases in distribution costs are primarily due to capital additions and ongoing infrastructure modernization and improvements to the distribution system for wildfire mitigation, which have increased rate base, as discussed on page 13. Also, noted is a big increase in O&M. This is largely attributable to the timing and approval of SCE's 2021 GRC decision that authorized higher wildfire mitigation and vegetation management expenses, and authorized significantly higher wildfire liability insurance coverage. The O&M for 2021 also includes SCE's recovery of drought-related catastrophic event expenses.

[22] In the past, utilities were authorized costs for safety-related programs without the use of a balancing account. If a utility spent less, then it could retain the net revenues, including profits, for those programs. To prevent the utilities from profiting from safety-related programs, the CPUC adopted balancing accounts for these programs. One ratemaking mechanism is to cap safety spending in a "one-way" balancing account to avoid ratepayers paying costs above authorized and to have the utilities refund any net revenues to ratepayers instead of retaining them. More often of late, the CPUC uses "two-way" balancing accounts for safety costs to allow utilities to recover much needed expenditures from ratepayers for safety spending such as wildfire prevention. Utilities are prevented from profiting off this system, and if a utility spends more than authorized, it may seek to recover its additional spending as directed when the account is established.

[23] When adjusted for inflation, the 2011 total distribution revenue requirement equals $10.4 billion, which indicates distribution revenue requirement has increased approximately 32 percent from 2011 to 2021 (in 2021 dollars).

[24] Adjusted for inflation.

Figure 3.2: Trends in Distribution Revenue Requirement

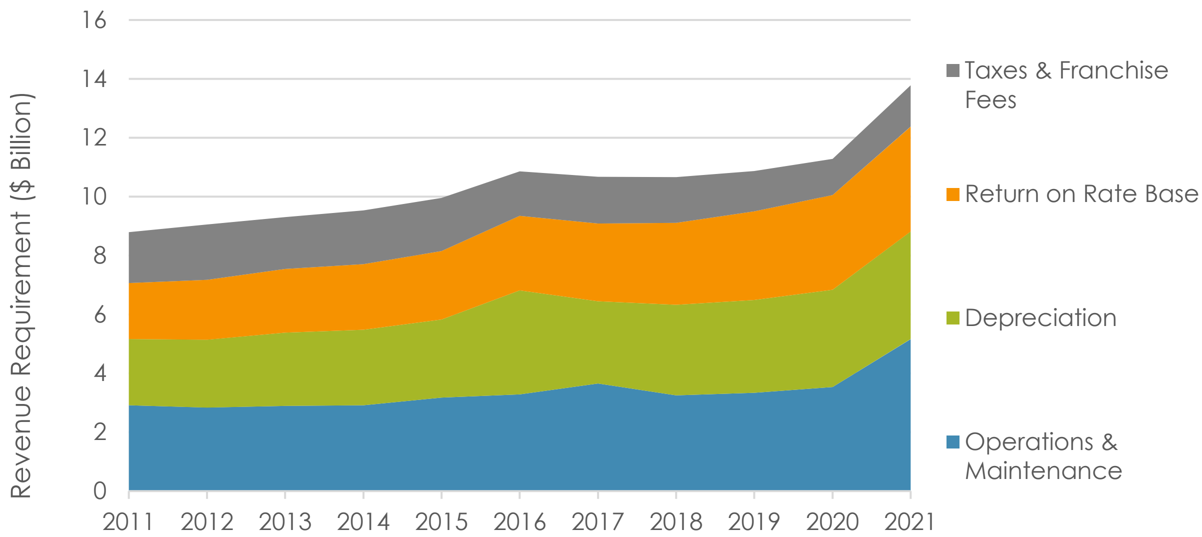


Table 3.2 below shows the contributions of distribution components to the 2021 revenue requirement.

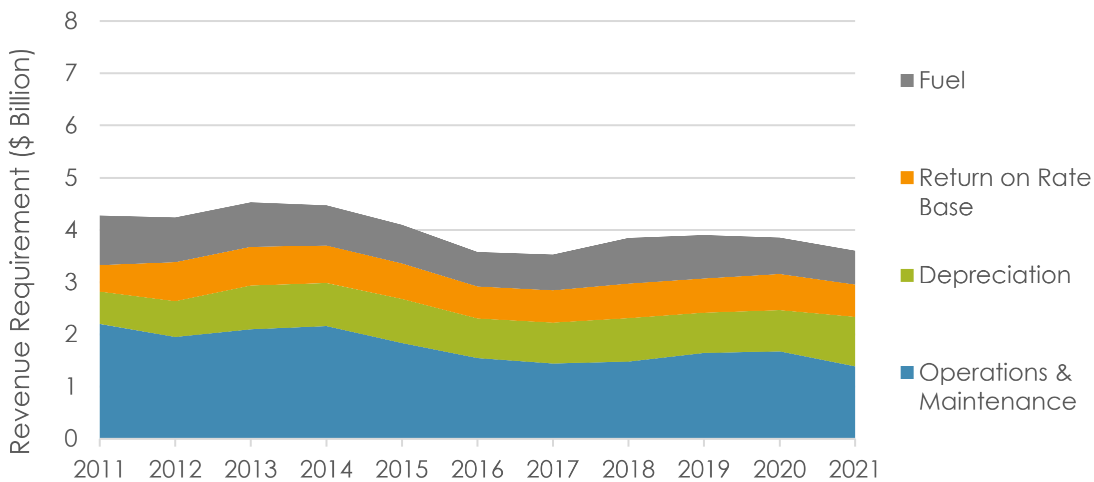
Table 3.2: 2021 Distribution Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	2,174,433	2,250,040	735,265
Depreciation	1,586,711	1,702,085	370,070
Return on Rate Base	1,283,422	1,964,250	309,893
Taxes and Franchise Fees	550,920	671,312	184,466
Total	**5,595,486**	**6,587,686**	**1,599,694**

Utility Owned Generation Revenue Requirements

The revenue requirement for utility-owned (or retained) generation (UOG) includes O&M costs, depreciation, and return on rate base related to these facilities. As older generating 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 3.3**. 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.

Figure 3.3: Trends in Generation Revenue Requirement



*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 fossil-fueled generation, UOG (including fuel costs) now accounts for only 9 percent of their combined revenue requirements. The 2021 generation revenue requirement for the electric IOUs is shown in **Table 3.3**.

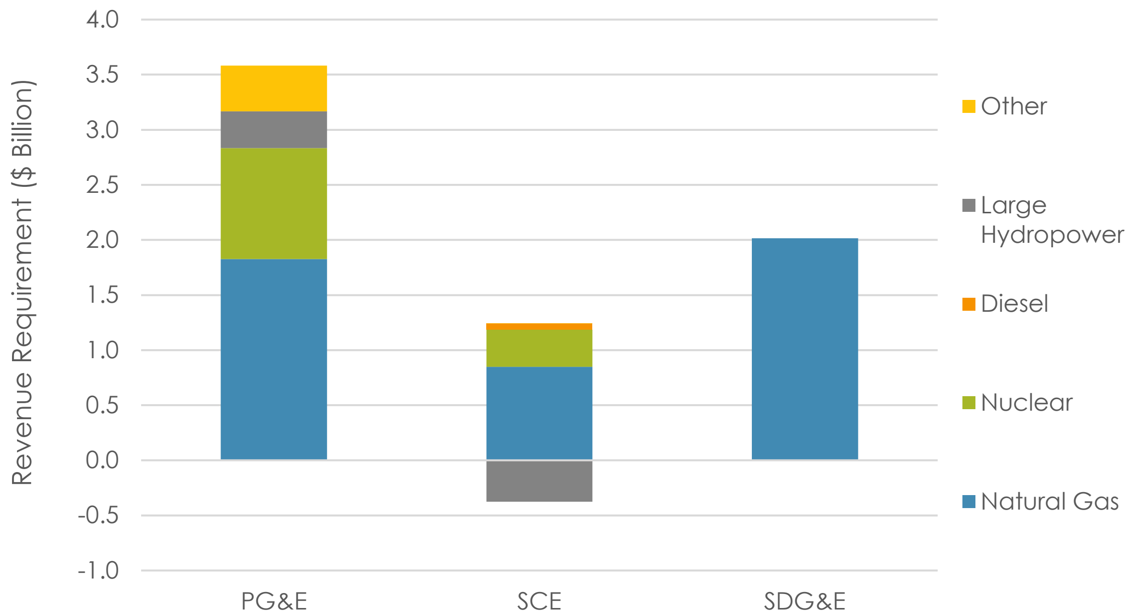
Table 3.3: 2021 Generation Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	999,032	302,015	87,498
Depreciation	695,507	200,856	50,201
Return on Rate Base	380,532	194,956	45,454
Total	**2,075,071**	**697,827**	**183,152**

Figure 3.4 shows the components of the 2021 UOG revenue requirement by sources. PG&E's UOG consists primarily of nuclear power (Diablo Canyon) and several natural gas plants (e.g., the 660-megawatt (MW) Colusa Generation Station, 580 MW Gateway Generating Station, and 163 MW Humboldt Bay Generating Station). SCE's UOG portfolio consists primarily of nuclear (Palo Verde Nuclear Generating Station) and natural gas power plants, including the 1,035 MW Mountain View Power Plant and Peaker plants. SDG&E's UOG includes natural gas plants: the 560 MW Palomar Energy

Center, the 96 MW Miramar Energy Facility, the 495 MW Desert Star Energy Center, and the 42 MW Cuyamaca Peak Energy Plant.[25]

Figure 3.4: 2021 Revenue Requirements of UOG Sources



*SCE's negative Large Hydopower value is due to lower than forecasted load, which resulted in overcollections. These overcollections were returned to ratepayers in 2021.

Table 3.4: 2021 UOG Sources Revenue Requirements ($000)

	PG&E	SCE[26]	SDG&E
Natural Gas	182,738	84,912	201,568
Diesel	0	5,413	0
Nuclear	100,615	33,741	0
Other	41,539	398	0
Large Hydropower	33,441	(37,719)	0
Total	**358,334**	**86,745**	**201,568**

[25] Desert Star Energy Center was purchased from Sempra Natural Gas in October 2011 and Cuyamaca Peak Energy Plant was purchased in January 2012.

[26] SCE's negative Large Hydropower value is due to lower than forecasted load due to several outages in 2021, which resulted in overcollections. These overcollections were returned to ratepayers in 2021.

Nuclear Revenue Requirement

SCE and SDG&E hold joint ownership in San Onofre Nuclear Generating Station (SONGS) and SCE holds partial ownership in the Palo Verde Nuclear Generating Station (operated by Arizona Public Service).[27] Due to operating issues at SONGS, this facility was taken offline in the first quarter of 2012 and permanently shut down in June 2013. In 2014, SCE and SDG&E were authorized by the CPUC to purchase replacement power to alleviate the capacity shortfall. Ratepayer and SCE/SDG&E shareholder responsibilities for SONGS-related costs were determined in a 2014 decision in the SONGS Investigation, which was subsequently re-opened to determine whether that decision represented a fair and equitable balance between ratepayer and shareholder recovery. A final decision on SONGS related costs was issued in August 2018 (D.18-07-037).

As part of SONGS' original coastal development permit issued in 1974, the California Coastal Commission (CCC) required SCE to mitigate adverse impacts on the marine environment. In 2016, as part of that directive, the CCC required SCE to update the configuration of the Wheeler North Reef (WNR), an artificial kelp reef project created in 1999. Following completion of the WNR project, SCE and SDG&E submitted final recorded costs in 2021 Advice Letters 4501-E and 3759-E respectively, showing the project had cost $0.17 million less than authorized. That $0.17 million was refunded to ratepayers as part of SCE's and SDG&E's 2022 Energy Resource Recovery Account (ERRA) Forecast decisions, D.22-01-003 (SCE) and D.21-12-040 (SDG&E).[28]

PG&E owns and operates the Diablo Canyon Nuclear Power Plant. In January 2018, the CPUC approved a joint request by PG&E and other parties to shutter the plant's two generating units in 2024 and 2025 (D.18-01-022) and approved ratepayer funding of $241.2 million for employee retention and retraining ($222.6 million) and license renewal activities ($18.6 million). In September 2018, SB 1090 authorized an additional $225.8 million in funding for the shutdown of Diablo Canyon Nuclear Power Plant, with $140.8 million of that amount for employee retention programs and $85 million for a Community Impact Mitigation Program (see also D.18-11-024). In total, $467 million in ratepayer funding was approved. Diablo Canyon's forecast 2021 Operating Costs (i.e., O&M) were $334 million while its forecast 2021 capital expenditures were $22 million (see A.21-06-021 testimony).

SCE owns a 15.8 percent share of the Palo Verde Nuclear Generating Station located near Phoenix, Arizona. Arizona Public Service Company (APS) operates Palo Verde while SCE compensates APS for its 15.8 percent share of expenses. SCE also oversees and reviews Palo Verde operations through participation in two committees. SCE's

[27] In addition to the list of UOG resources above, SCE also owns and operates a diesel generating facility on Santa Catalina Island. Since the island's load is not connected to the grid, the supply and demand are not included in the forecasts, but the expense is included in the revenue requirements.

[28] In 2018, the CPUC approved D.18-03-027 which ordered SCE and SDG&E to update WNR forecast costs and present them to the CPUC for approval. Subsequently, Resolution E-5032 authorized $21.04 million in revenue requirement for WNR, which was later updated to $23.59 million in Advice Letters 4052-E (SCE) and 3422-E (SDG&E).

15.8 percent share of Palo Verde's 2021 operating costs (O&M) was approximately $73 million while its share of 2021 capital expenditures totaled approximately $36 million (see D.21-08-036).

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 September 2021, the Commission approved D.21-09-003 for PG&E's 2018 NDCTP, authorizing a proposed settlement agreement that allows PG&E to collect $112.5 million in annual revenue requirement for Diablo Canyon decommissioning costs from 2022 through 2029. In December 2021, the CPUC approved the 2018 NDCTP for SONGS, D.21-12-026, in which SCE and SDG&E requested no rate changes.

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:[29]

- Fees for disposal and storage of spent nuclear fuel are required by the 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 proceedings (see D.21-09-003 and D.21-12-026).

- 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.

Authorized Rate of Return

Authorized rate of return on rate base (ROR) is the weighted average cost of capital 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

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

which are adopted in separate Cost of Capital proceedings held every three years. The financing of IOU capital expenditures, or rate base, is included in adopted revenue requirements as part of the cost of service.

Figure 3.5 illustrates the CPUC authorized ROR since 2011 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. **Figure 3.6** shows trends in the CPUC authorized ROE component of ROR since 2011.

Figure 3.5: Trends in Weighted Average Rate of Return (ROR)

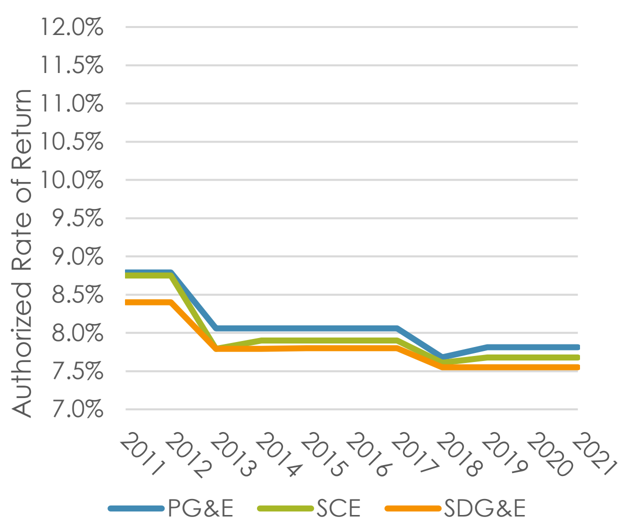


Figure 3.6: Trends in Return on Equity (ROE)

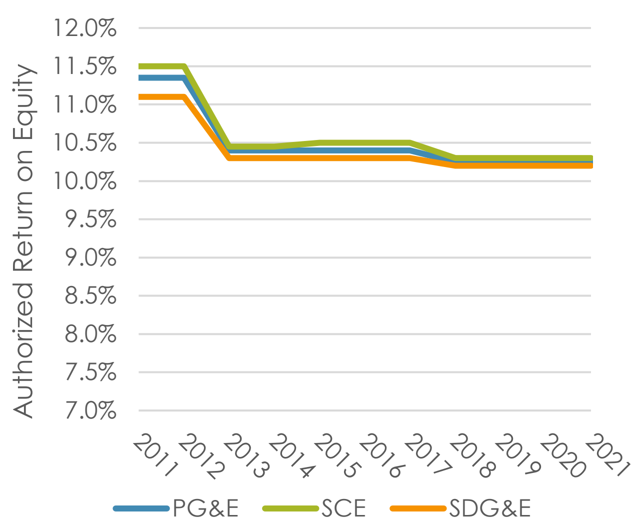
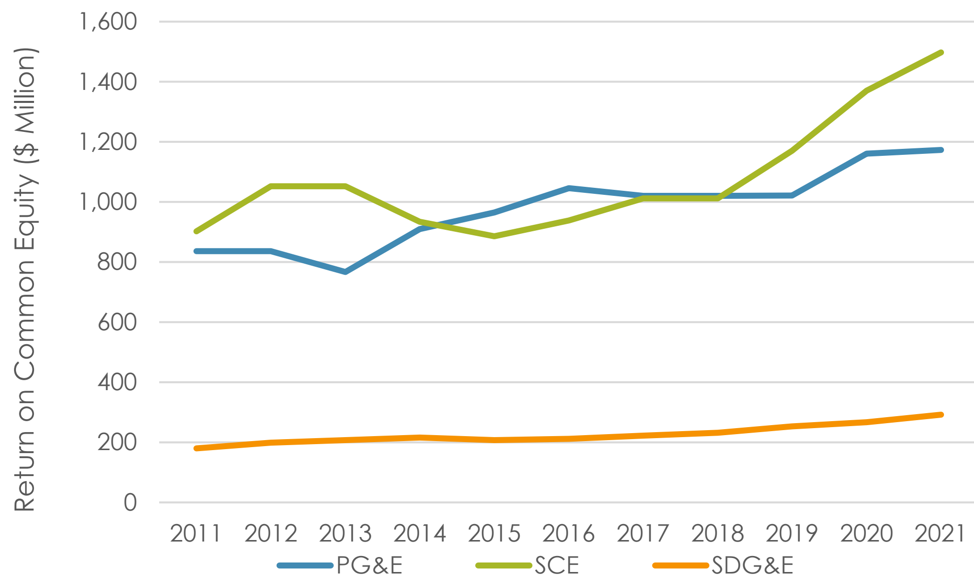


Figure 3.7 shows trends in dollars authorized for return on common equity for major energy utilities since 2011. The figure does not include return on common equity authorized by FERC for IOU transmission systems; it includes only the return on common equity authorized by the CPUC for UOG and distribution.

Figure 3.7: Dollar Trends in Authorized Return on Common Equity



The major energy utilities are currently required to file a cost of capital application every three years, although this review cycle can be, and has sometimes been, extended. In April 2019, SCE, SDG&E, and PG&E filed their 2020 cost of capital applications. In D.19-12-056, the CPUC established the 2020 through 2022 cost of capital for SCE, PG&E, and SDG&E. In August 2021, SCE, SDG&E, and PG&E filed applications requesting relief from the cost of capital adjustment mechanism established in 2008, a full review of the authorized cost of capital using test year 2022, and for modification of the three-year cost of capital cycle thereafter. These applications are currently pending before the CPUC.

Transmission Revenue Requirement

Background and Jurisdictional History

As part of energy restructuring, the CAISO was created by the legislature and given operational control[30] over the utilities' high voltage transmission lines on March 31, 1998, and authority for determining transmission revenue requirements was transferred to FERC.[31] The transmission revenue requirements (TRR) authorized by FERC include the

[30] The Restructuring Decision (1996) functionally created the implementation of the CAISO through the acceptance of AB 1890 (Sept. 24, 1996).

[31] FERC Order 888 and 889 (April 1996) required utilities to open transmission grids for access by all generators on a nondiscriminatory basis and functionally unbundled rates for generation, transmission, and ancillary services. The CPUC acceded to this regulatory transfer in its Electric Restructuring Decision D.95-12-063 (Dec. 20, 1995).

same core components (e.g., cost-of-service, depreciation, cost of capital, and taxes) as the general rate cases at the CPUC.

Components of the electric grid are considered part of the transmission system and under FERC jurisdiction if they are high-voltage and meet FERC criteria for connectivity in the transmission system. Each utility defines its high-voltage transmission lines differently. PG&E, SCE, and SDG&E define all power lines at and above 60 kV, 200 kV, and 69 kV, respectively, as transmission-level assets that are regulated by FERC. These high voltage networked parts of the grid fall under CAISO's operational control and FERC's regulatory jurisdiction. All other electric power lines and assets remain under CPUC regulatory control and jurisdiction.

Currently, the three major IOUs file Transmission Owner (TO) formula rate cases at FERC, establishing rates of depreciation and cost of capital for the next several years.[32] A formula provides a structure through which necessary expenses and capital costs can be implemented, as well as the opportunity for annual true-ups to account for over- or under-collection in rates. Further, a formula prevents the need for an entirely new rate case at FERC every year. As an update to last year's Report, in October 2020, FERC finally issued a final order on most of the issues in PG&E's TO18 rate case, which was litigated for 2017 rates at FERC. However, because FERC has changed its methodology on how to calculate the return on equity ("ROE") authorized for recovery from ratepayers on its capital plant, parties (including the CPUC) briefed this issue in late 2020 and early 2021. The CPUC eagerly awaits a decision on the ROE issues in TO18, as the settled outcome of TO19 for 2018 rates is tied to a final decision in TO18.

Transmission Revenue Requirements and Trends

The CPUC is the statutorily-designated agency representing the interests of California retail ratepayers in TO rate cases at FERC[33] and advocating for containing ratepayer costs in the TO rate cases. The CPUC actively participates in TO rate cases before FERC to advocate for just and reasonable rates in transmission ratemaking proceedings. Due to the importance and complexity of these rate cases, CPUC Legal Division and Energy Division staff analyze a multitude of expenses and capital projects for cost effectiveness, reliability, safety, and overall prudence of expenditures. Specific TRR components examined include return on equity, capital structure, taxes, depreciation, cost-of-service, and the forecast of expenses of transmission capital projects. FERC approves just and reasonable Transmission Revenue Requirement (TRR) for the IOUs. [34]

When the IOUs file a new rate case at FERC, the CPUC team, other joint intervenors, and FERC staff review, analyze, and conduct discovery on the utilities' filings to collect

[32] Prior to 2018, PG&E filed a stated-rate case annually at FERC. These annual rate cases typically ended with so-called "black box" settlements where the costs of specific components of the transmission revenue requirement are not provided, but instead a lump sum revenue requirement is settled on to determine rates. Unlike formula rate cases, these annual stated-rate cases provided no opportunity to true-up amounts over- or under-collected in rates.

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

[34] In general, although the CPUC has jurisdiction over the environmental review and siting of many large and/or capacity expanding transmission projects, FERC has jurisdiction over the revenue requirement for such projects.

evidence and develop a fact-based recommendation on what they believe is a just and reasonable revenue requirement to protect ratepayers. FERC sets the case for hearing, unless the parties reach a settlement as they did in PG&E's TO18 rate case, and ultimately decides how the various rate case components will result in a just and reasonable TRR.

In October 2018, PG&E filed its Twentieth Transmission Owner Formula Rate Case (TO20) at FERC. Settlement of all issues was accepted by FERC on December 30, 2020, with the term of the formula rate effective through 2023. The CPUC had success negotiating the establishment of the Stakeholder Transmission Asset Review (STAR) Process. As over 70 percent of PG&E's capital projects (i.e., nearly $1 billion annually) receive no review by the CAISO or CPUC, the STAR Process provides stakeholders with the opportunity to review substantial data on future projects, participate in stakeholder meetings, and seek additional information to understand, and provide input to, PG&E's capital spending.

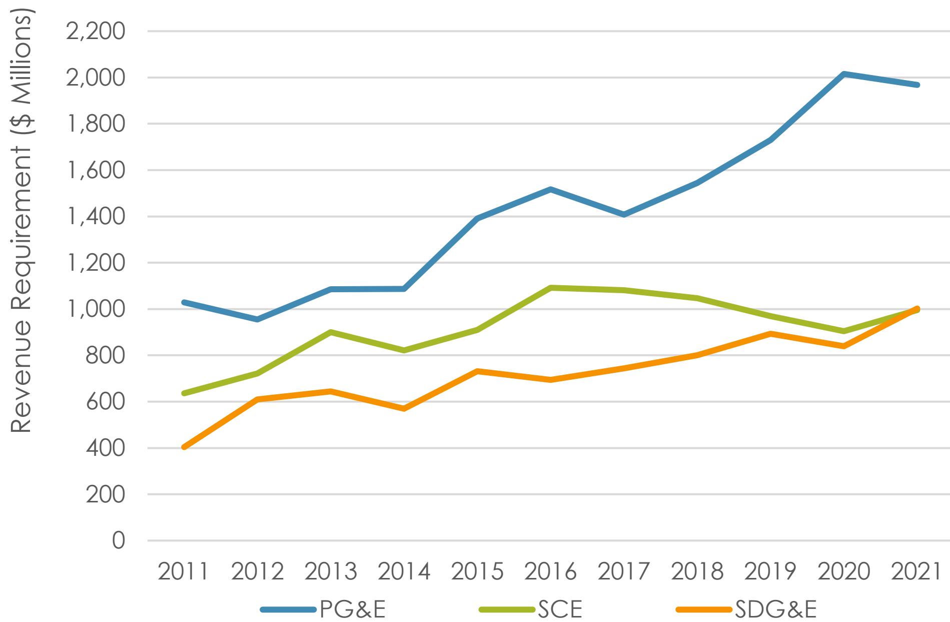
In SCE's case, parties reached a settlement agreement on July 1, 2020, and FERC approved the settlement on September 23, 2020. The settlement required annual Informational Filings to correct any under- or over-collection of approved expenses from the previous year. Further, SCE committed to establish and maintain a Stakeholder Review Process (SRP) for review of SCE's Five-Year Transmission Investment Plan for transmission projects and costs. SCE submitted its second semi-annual SRP to stakeholders for review on December 1, 2021.

SDG&E filed its fifth (TO5) formula rate application on October 30, 2018, and parties successfully negotiated an uncontested settlement approved by FERC on January 24, 2020. For the duration of the rate formula SDG&E will file Annual True Up transmission rate filings with FERC to reconcile differences between forecast and actual expenditures and other factors affecting their transmission revenue requirement.

The estimated savings from FERC Transmission cases bring the cumulative savings from 2008 to 2021 to approximately $2.8 billion for California ratepayers. Additional savings from negotiations in the unresolved PG&E rate cases are anticipated.

Even with the savings for ratepayers secured by the CPUC's efforts, transmission revenue requirements for the IOUs have been trending up since 2011, increasing at an average annual growth rate of 9.11 percent for PG&E; 5.65 percent for SCE; and 14.83 percent for SDG&E as shown in **Figure 3.8**.

Figure 3.8: Trends in Transmission Revenue Requirement[35]



Historically, much of the increase in the utilities' revenue requirements has been due to transmission infrastructure capital investments. In the past years, reasons for these increases have included CAISO-approved reliability projects and those needed for meeting Renewables Portfolio Standard (RPS) mandates. These projects expand capacity of the grid, enabling interconnection of new electric generation to the grid, as well as compliance with North American Electric Reliability Corporation (NERC) requirements.

The current trend in transmission capital investment shows that all three electric utilities are increasing their spending on "self-approved" transmission projects. "Self-approved" means there is no existing requirement that these projects undergo review for cost or need by CAISO, CPUC, or any other third party. The three electric utilities report that from 2011 to 2020, these self-approved transmission projects accounted for 42 percent ($8.9 billion) of their collective transmission investment. However, in just the last three years for which the CPUC has actual data (i.e., 2018 to 2020), 63 percent ($3.9 billion) of the electric utilities' investments were on self-approved projects, as shown in **Table 3.5**.

[35] Does not include costs related to Reliability Services or Transmission Access Charge.

Table 3.5: 2021 Self-Approved Transmission Projects as a Share of Transmission Capital Investment

	2011-2020 ($M)	2018-2020 ($M)
Total IOU Transmission Capital Projects	21,309	6,145
Self-Approved Capital Projects	8,908	3,857
Percentage of Self-Approved Projects	41.8%	62.8%

While FERC has found that these self-approved projects do not fall under the planning requirements of existing FERC regulations, the CPUC and other stakeholders had success in 2020 negotiating PG&E's Stakeholder Transmission Asset Review (STAR) Process and SCE's Stakeholder Review Process (SRP) as parts of their respective TO rate cases at FERC. These stakeholder processes improve transparency of the two utilities' transmission capital projects planned for the next five years. While these stakeholder processes are important steps to help ensure that the IOUs are building the right projects in the right locations at the right times for safety and reliability of the modernizing grid, at this point they are scheduled to expire at the end of 2023 with the formula rates. Further steps are needed to sustain stakeholder engagement and visibility of these substantial capital investments in order to protect ratepayers while ensuring a safe and reliable grid.

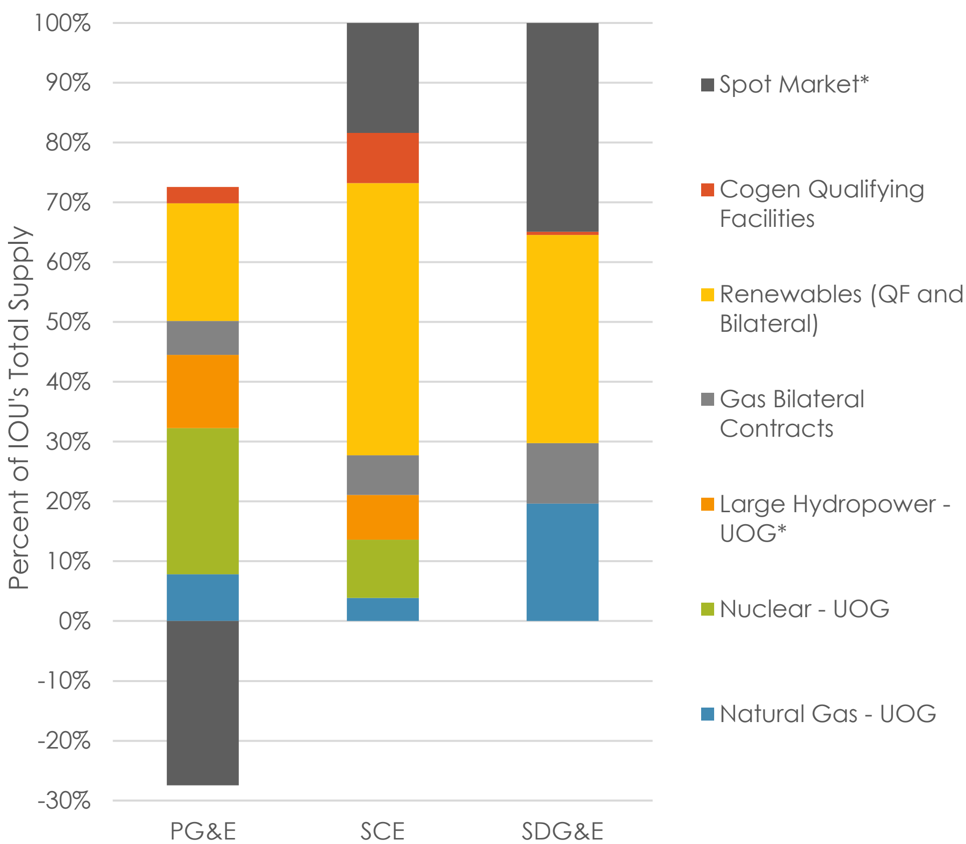
IV. Power Procurement Costs

The generation revenue requirement includes utility owned (or retained) generation (UOG) costs, as well as purchased energy and capacity costs. As previously noted, in the late 1990s the utilities divested almost all of their fossil-fueled generating plants during restructuring, and, as a result, they largely rely on purchased power for incremental electricity needs.

In 2021, purchased power accounted for approximately 70 percent of the total generation revenue requirement, while UOG comprised about 6 percent (see **Figure 4.1**). Power purchase costs represented the largest component of forecasted generation costs and accounted for 25 percent of total revenue requirements. Recovery of these pass-through costs is authorized through the ERRA proceedings. The sale of purchased power is expensed, not capitalized.

PG&E's negative spot market value is due to the formation of several CCAs that left PG&E with excess energy to serve bundled load, which PG&E sold in 2021 spot markets.

Figure 4.1: 2021 Forecast Energy Supply for Electric Utilities



*Includes Other

Background

Heavy reliance on power purchases rather than UOG began with the enactment of AB 1890 in 1996, which restructured the electric utility industry in California and created the CAISO and the Power Exchange. To create a competitive electricity market in which non-utility suppliers would compete with the utilities in the wholesale generation market, the utilities were encouraged to divest at least 50 percent of their fossil-fueled generation. The CPUC provided a rate of return (ROR) incentive to the utilities to encourage them to divest. As a result, the utilities sold a substantial portion of their fossil-fueled generation.

During the 2000-01 energy crisis, the utilities were exposed to high market prices for electricity, due in large part to the divestiture of their generating plants. Authorized utility rates, which were frozen at pre-restructuring levels from June 1996, were no longer sufficient for the utilities to cover the high costs of purchased power; PG&E filed for bankruptcy and both SCE and SDG&E faced substantial financial uncertainty. In response, the Legislature enacted AB 1X, which authorized the DWR to enter into power purchase contracts to stabilize the severely disrupted energy markets.

In 2002, the Legislature enacted AB 57 to return energy procurement responsibilities to the utilities. The legislation required the CPUC to adopt a Long-Term Procurement Plan to ensure sufficient resource availability over time. The legislation also established guidelines for procurement solicitations, cost recovery of power purchases, and integration of renewable resources using long-term planning. The contracts resulting from these solicitations are reviewed by Procurement Review Groups[36] that the CPUC required the IOUs to create.

AB 380 (2005) further addressed CPUC responsibilities for resource planning, requiring the CPUC, in consultation with the CAISO, to establish resource adequacy requirements to ensure that adequate physical generating capacity would be available to meet peak demand. Consequently, the utilities (and all load-serving entities) are required to maintain a 15-17 percent planning reserve margin for generating capacity to ensure they have sufficient capacity available or under contract to serve their forecasted load.

In addition, SB 1078 (2002) established the RPS and required the utilities to serve 20 percent of their electricity demand with renewable resources by 2017. The statute also required each IOU to hold an annual solicitation to procure renewable power. SB 107 (2006) later increased the RPS obligation to 20 percent by 2010 and was

[36] A Commission authorized forum that reviews procurement activities including contracts and reasonableness criteria and offers assessments and recommendations to each utility. The Commission initially established Procurement Review Groups (PRG) in D.02-08-071 as an advisory group to assess the investor-owned utilities' procurement strategy and processes, as well as specific proposed procurement contracts. The PRG includes non-market participants, as well as Energy Division and Cal Advocates.

updated by SB 2 (2011) when the RPS obligation was raised to 33 percent by 2020. SB 350 (2015) raised the RPS obligation to 50 percent by 2030. In 2018, SB 100 set the current RPS obligation to 60 percent by 2030 and the planning goal of obtaining 100 percent of electric retail sales to end-use customers from renewable energy and zero-carbon resources by 2045.

Types of Purchased Power

Department of Water Resources (DWR) Contracts

The California Department of Water Resources (DWR) entered into long-term contracts on behalf of IOU customers during the energy crisis. Each year, DWR had submitted its revenue requirement to the CPUC for adoption and subsequent collection from, or refund to, ratepayers through the DWR Power Charge. Due to the recent expiration of these contracts, DWR's Power Charge revenue requirement for all three utilities was zero. Proceeds from litigation related to these contracts is possible in the coming years and will result in future refunds to customers if realized.

Qualifying Facilities (QFs)

Qualifying Facilities (QFs) are co-generation and renewable generation facilities that qualify to sell power to the utilities under the Federal Public Utility Regulatory Policies Act (PURPA). These facilities must meet FERC's requirements for ownership, size, and efficiency to qualify as QFs. PURPA requires IOUs to interconnect with, and purchase power from, QFs at rates that reflect costs the utility avoids by buying QF power instead of procuring power from other sources. In 2011, the CPUC approved the QF/Combined Heat and Power (CHP) Program Settlement which suspends the "must-take" obligation for QFs over 20 MW and establishes new energy prices for QFs.[37] In 2015, the CPUC added an Emissions Reduction Target associated with CHP procurement of 2.72 million metric tons of greenhouse gas (GHG) Emissions Reductions by 2020.[38] The Settlement ended in 2020, with SDG&E required to do an additional CHP solicitation in 2022 to meet its obligations under the Settlement.[39] In 2020, the CPUC adopted a new Standard Offer Contract for QFs, including new avoided cost energy and capacity prices established either at time of contract execution or at time of product delivery.[40]

Figure 4.2 and **Figure 4.3** break out QF supply and revenue requirements for cogeneration and renewable energy. Since 2005, the total energy supply provided by all QFs has decreased, and the QF revenue requirement has decreased by approximately $1.2 billion. Over the same time period, the revenue requirement for cogeneration QFs has decreased as older contracts expire, and the revenue requirement for renewable QFs has increased.

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[37] QF costs include Competition Transition Charges (CTC). For a breakout, see table in Appendix A.

[38] CPUC D. 15-06-028, issued on June 15, 2015.

[39] CPUC Resolution E-5163, issued on August 20, 2021.

[40] CPUC D. 20-05-006, issued on May 15, 2020.

Figure 4.2: Trends in Purchased Power Supply (GWh)

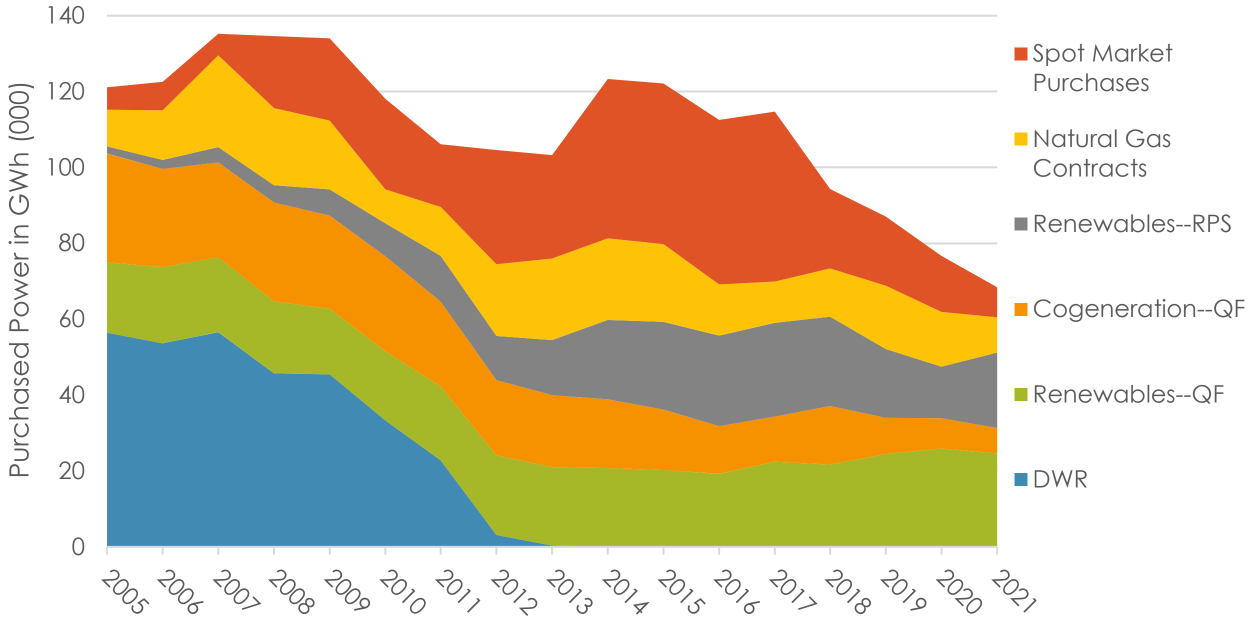
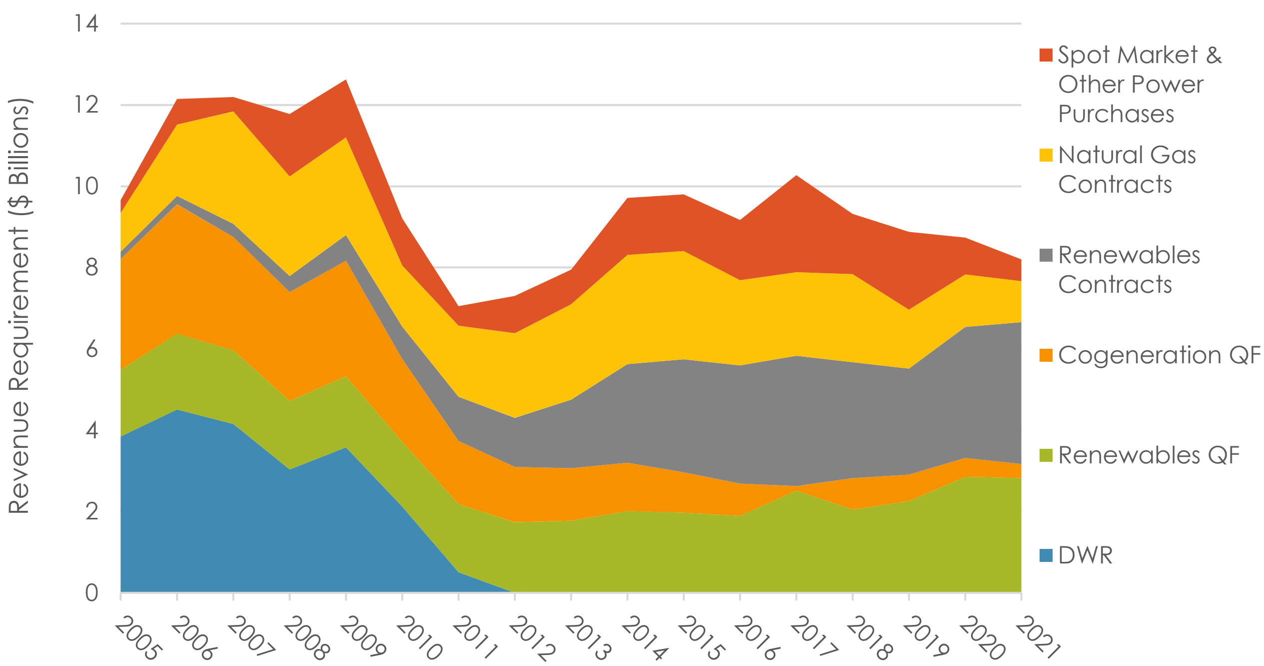


Figure 4.3: Trends in Purchased Power Revenue Requirement



Bilateral Natural Gas Contracts

Bilateral contracts are contracts entered into directly between a utility and an independent power supplier –either a generator or trader-- and are generally sourced by the utilities through a Request for Offers (RFO) open solicitation process. Bilateral contracts can include capacity and energy, usually in the form of a tolling arrangement, or they can be capacity only contracts. Capacity contracts pay generators to be available to produce power and ensure that sufficient capacity is available to meet load.

Renewable Energy Procurement

The IOUs exceeded their 33 percent by 2020 RPS targets through their procurement of online renewables generation. The excess procurement of renewable energy resulted in surplus or "banked" renewable energy credits, or RECs, which the IOUs may choose to apply towards future RPS requirements instead of procuring incremental renewable resources. In addition to banking excess RECs, for the past several years the IOUs have sold small quantities of their excess REC supply and returned the revenue of these sales to rate payers. After accounting for the sale of excess RECs, the IOUs forecast having served 47 percent of their electricity demand with RPS eligible resources in 2021. The IOUs have forecasted RPS percentages over 50 percent in 2022 and beyond without any voluntary allocations.[41] The weighted average RPS procurement expenditures for the IOUs has increased from 9.4 ¢/kWh in 2003 to 9.9 ¢/kWh in 2019,[42] and 10.4 ¢/kWh in 2020, in real dollars. [43]

Other Power Purchases

Additional power purchase and sale mechanisms exist to ensure that the utilities secure sufficient capacity to balance load across the grid and meet peak load requirements at least cost.

- **Spot Market Purchases:** This term refers broadly to power that the utilities buy from the CAISO's Day-Ahead market to balance the system on a day to day basis. IOUs use the spot market to balance their forecasted load requirements for the following day through transactions that may occur in the CAISO market.

[41] Decision (D.) 21-05-030 issued on May 24, 2021, ordered the IOUs to offer PCIA-eligible LSEs voluntary allocations of PCIA-eligible resources.

[42] Initial average annual RPS expenditures were lower than current expenditures for the program. This is because in 2003, at the beginning of the RPS program, the large IOUs' RPS resources consisted primarily of heavily depreciated wind and small hydroelectric facilities. Starting in 2010, new resources from contracts that were signed around 2007 began coming online, which increased average RPS expenditures.

[43] The increase in 2020 was due to more diversified procurement of renewable generation from technologies such as bioenergy, geothermal, small hydro, and wind, which are higher in price compared to solar PV, which was the primary technology procured in 2019.

- **Net Long Sales:** These are sales that the utilities make when their expected supply exceeds their forecasted load. These sales reduce ratepayer costs by generating revenue from excess capacity not likely to be needed.
- **Inter-Utility or Power Exchange Agreements:** Traditionally, regulated utilities enter into seasonal and long-term inter-utility exchange agreements with other regulated utilities and other load-serving entities. Through bilateral negotiations the specific terms are crafted to best fit the resources and needs of both parties. Payment is typically in the form of non-cash exchanges of capacity and energy balanced to reflect the seasonal and locational value of the power. Different peaking times in the northwest and southwest lead to large-scale transactions.
- **Real-Time Market and Reliability Services:** CAISO has certain agreements with generators to provide reliability services. The CAISO spreads the costs of these reliability services among the load-serving entities. In addition, the CAISO buys power in the real-time market to balance resources and loads and charges the load-serving entities whose short supply necessitated real-time purchases.

Greenhouse Gas Costs and Allowance Proceeds

Since January 1, 2013, electric utilities have been regulated under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the electric utilities must secure compliance instruments, known as offsets and allowances, and surrender them to the California Air Resources Board (CARB) to account for their GHG emissions. CARB holds quarterly allowance auctions where entities can buy and sell allowances. Utilities can also procure compliance instruments on secondary markets or through contractual arrangements.

The Cap-and-Trade Program requires the utilities to comply on their customers' behalf for the emissions associated with the energy customers use. For electric utilities, compliance costs come in the form of a direct compliance obligation for utility-owned generators and generators under contract (which must also buy and surrender compliance instruments), as well as indirect costs from wholesale market transactions or power contracts with pricing terms that include GHG emission costs.

Beginning in 2014, the electric utilities started introducing Cap-and-Trade Program related costs into electricity rates and distributing allowance proceeds to residential customers via the California Climate Credit, applied to customer bills twice a year. Small Business customers and emissions-intensive trade-exposed industrial customers also began to receive credits in 2014.

Utilities accrue costs for the Cap-and-Trade Program as both direct and indirect costs. In 2021, the electric utilities collectively included approximately $173 million in direct GHG costs into rates and returned approximately $773 million in allowance proceeds to customers in the form of customer credits (see **Table 4.1**). Customers also incur indirect costs for the Cap-and-Trade 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-Trade Program compliance costs are included in the "Purchased Power" row of Table 2.1 (2021 Electric IOU Authorized Revenue Requirements), but are not reported separately in this section.

Table 4.1: 2021 Summary of Greenhouse Gas Costs and Allowance Proceeds[44]

Utility	2021 Electric GHG Direct Costs Revenue Requirement[45]	2021 Electric Proceeds Distributed to Customers
PG&E		($258,343,617)
SCE		($405,143,559)
SDG&E		($109,622,009)
Total	**$172,557,837**	**($773,109,185)**

Each year, CARB allocates allowances to electric utilities on behalf of their ratepayers. The Cap-and-Trade Program requires the investor-owned electric utilities to sell all of these allowances at CARB's quarterly allowance auctions in the year they are allocated. The proceeds the utilities receive from the sale of GHG allowances must be used exclusively for ratepayer benefits, consistent with the goals of AB 32 (2006), CARB regulations, and as directed by the CPUC. Consistent with the direction in SB 1018 (2012), the CPUC has determined the methodologies the utilities should use to return proceeds to industrial customers ("emissions-intensive and trade-exposed"), small business, and residential customers.

In addition to customer credits, up to 15 percent of allowance proceeds may be used for clean energy or energy efficiency programs. AB 693 (Eggman, 2015) directed up to $100 million of allowance proceeds be allocated annually to solar energy systems in disadvantaged communities. In response, the CPUC established the Solar on Multifamily Affordable Housing (SOMAH) program in December 2017. In 2020, CPUC determined that as proceeds are available and there is adequate participation and interest in SOMAH program, allocation of funds to the SOMAH program will continue through June 30, 2026. For the first time, in 2021 SOMAH was funded at the $100 million ceiling. In 2018, in response to AB 327 (Perea, 2013), the CPUC developed the Disadvantaged Communities Single-family Solar Homes program (DAC-SASH; $10 million, annually), and the Community Solar Green Tariff and Disadvantaged Communities-Green Tariff (DAC-GT) programs (funding provided as needed and available) to encourage growth of renewable generation among residential customers in disadvantaged communities, both of which are funded first with allowance proceeds

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[44] Proceeds recorded through September 30, 2021 and estimated through December 31, 2021. Costs recorded through August 31, 2021 and estimated through December 31, 2021 for SCE. Costs recorded through September 30, 2021 and estimated through December 31, 2021 for PG&E and SDG&E. Proceeds for bundled and unbundled customers; costs for bundled customers only. In August 2021 CPUC passed D.21-08-026, which changed Cap-and-Trade proceed reporting requirements to allow for proceeds to be tracked separately for bundled and unbundled customers starting in 2022.

[45] Due to confidentiality, some cells have values that were redacted.

and, if those are exhausted, through public purpose programs (PPP) funds. Additionally, in 2019 the CPUC also approved use of $20.4 million by SCE for a Clean Energy Optimization Pilot, of which $10 million was appropriated from Cap-and-Trade funds in 2020. An inventory of demand side management programs funded out of the IOUs' GHG auction proceeds can be found in section V.

In August of 2021, the CPUC issued D.21-08-026, which approved changes to the distribution methods and reporting of allowance proceeds. The decision provided that the CPUC's implementation of the Cap-and-Trade Program is in compliance with CARB regulations by removing volumetric returns and ensuring the uninterrupted delivery of customer credits through 2030.

Other Factors Affecting Electricity Generation Costs

Prior sections have described many factors that cause energy generation and procurement costs to vary significantly between different types of procurement and over time. Natural gas prices are another factor that can have a significant effect on the cost of many types of generation:

> **Natural Gas Prices:** Natural gas prices cause generation costs to be more volatile than other forms of generation. Electric spot market purchases, DWR contracts, and cogeneration QFs costs fluctuate and track with gas prices. Natural gas bilateral contracts do not track as closely with gas prices, as most of the costs of those contracts are associated with capacity and not energy. Renewables contracts generally exhibit more cost stability because they are not reliant on gas prices.

If generation costs are significantly higher or lower than forecasted,[46] the affected utility must file an ERRA Trigger notification with the CPUC's Energy Division. If the utility does not believe that the difference will be within the threshold amount within 120 days, it files an expedited ERRA application (Trigger) that corrects rates to be in line with the costs the utility is experiencing. The Trigger application maintains rate stability if the costs associated with fuel and purchased power vary greatly from forecasted amounts.

The CPUC conducts annual Compliance ERRA reviews that true-up any difference from the utility's forecasted revenue requirement to the actual costs incurred regardless of whether or not a Trigger application was filed.

In 2021, natural gas prices rose around the world due to increased demand without a similar increase in supply. Additionally, a major natural gas pipeline outage and a Polar Vortex created deliverability concerns and supply reductions and impacted the prices of natural gas in the western states, including California.

[46] The utility must alert the CPUC if a balance grows to greater than 4 percent more or less than revenue requirement per D. 02-10-062; if the balance is expected to cross 5 percent the utility must file an expedited application known as an "ERRA Trigger Application".

Initially, during the COVID-19 Pandemic, natural gas prices fell as demand for natural gas fell. This decrease in prices helped to offset the overall decline in demand for electric sales and prevented undercollections from occurring in utility generation regulatory accounts.

Weather: Weather continues to play a role in varying electricity prices. For example, the summer heat waves of 2020 throughout California caused electricity prices to spike to extreme highs during peak demand hours. 2021 was also a major drought year. Drought years in the western states mean less hydroelectric generation available and thus more reliance on natural gas-fired generation; all else equal, this tends to increase electricity prices. Additionally, there was particularly cold and wet weather in late 2021 that helped drive an increase in natural gas and electricity prices during that time. Variances in cost due to weather are addressed in the CPUC's annual ERRA Compliance and ERRA Forecast applications.

V. Demand-Side Management and Customer Programs

The Demand-Side Management (DSM) work that the CPUC oversees is characterized by a mix of energy efficiency (EE), demand response (DR), and distributed generation (DG) programs, serving all sectors of the California economy. For nearly half a century, the CPUC has overseen policies to encourage energy conservation, efficiency and load management. In 2003, the CPUC and the California Energy Commission adopted the Energy Action Plan to establish goals for the state's energy strategy.[47] The plan established that cost-effective energy efficiency and demand response are at the top of the loading order and are therefore the preferred means for meeting the state's growing energy needs, followed by renewable energy and distributed generation.

In addition California has led the nation in customer-side solar and other DG technology market growth, supported by the Self-Generation Incentive Program (SGIP) enacted in 2000, and, later in 2006, the landmark California Solar Incentive (CSI) program, both overseen by the CPUC. For decades the CPUC has administered low-income EE programs (now called Energy Savings Assistance or ESA) to assist vulnerable populations in managing their energy bills,[48] and takes input on these and other programs from the Low-Income Oversight Board (LIOB) established by the Legislature in 2001.[49]

Table 5.1 shows the DSM and customer program costs recovered in rates.

[47] The Energy Action Plan was updated in 2005 and 2008.

[48] PU Code Section 2790.

[49] SBX 2 (2001, Alarcon).

Table 5.1: 2021 Demand Side Management and Customer Programs Costs ($000)[50]

	PG&E	SCE	SDG&E	Total
Energy Efficiency	257,845	123,058	45,454	**426,357**
Demand Response	76,346	(1,706)	14,905	**89,545**
California Solar Initiative	7,955	0	0	**7,955**
Self-Generation Incentive Program	59,851	56,000	20,069	**135,921**
Electric Program Investment Charge	51,378	61,520	12,096	**124,994**
New Home Solar Partnership[1]	(36,668)	(26,724)	0	**(63,392)**
California Alternative Rates for Energy Admin	176,631	112,992	130,081	**419,704**
Energy Savings Assistance[2]	0	0	0	**0**
Other PPP Programs	14,272	155,165	58,097	**227,534**
Other Regulatory	18,246	280,093	195,067	**493,406**
Total	**625,857**	**760,397**	**475,769**	**1,862,024**

1. PG&E's and SCE's negative amount (overcollection) will be credited to customers.
2. The ESA budget for 2021 is shown as $0 due to program costs offset by the previous year unspent funds.

Energy Efficiency

In 2003, the California Energy Action Plan set energy efficiency at the top of the loading order, determining that the state should maximize all cost-effective energy efficiency investment over both the short and long-term. In D.04-09-060, the CPUC translated this policy into specific annual and cumulative numerical goals for electricity and natural gas savings by utility service territory, which are updated periodically as provided for in that decision. The CPUC-adopted energy savings goals are expressed in terms of annual and cumulative gigawatt hours (GWh), million-therms (MMtherms), and peak megawatt (MW) load reductions.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of rates. The electric portion is funded through the Procurement Energy Efficiency Balancing Account (PEEBA) to reflect the avoided generation and transmission and distribution upgrades that result from reduced electricity demand. The aggregated annual expenditures are approximately $635 million for 2020 and 2021 together (see **Table 5.2**).

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50 Revenue requirement for Demand Side Management, California Solar Initiative, Self-Generation Incentive Program, and other regulatory ($162 million for PG&E, $334 million for SCE, and $230 million for SDG&E) is collected through the distribution rate component.

Programmatic efforts in 2020 and the first three quarters of 2021 resulted in reported program savings of 1,154 GWh (or 167 MW) and 72 MMtherms.[51] According to the EPA,[52] that is enough electricity savings to power about 98,484 homes for one year, and enough gas savings to avoid the need for about one-tenth of a coal power plant.

These programs support residential, public, commercial, industrial, and agricultural sectors to overcome barriers to improving energy efficiency and realize savings for the ratepayer. In addition to the directly quantifiable savings and benefits, the CPUC also supported programmatic activities targeted at the long-term transformation of consumer energy markets through emerging technology development, marketing, education, training, and other initiatives. However, the savings benefits associated with these efforts are difficult to quantify and the CPUC has historically not done so.

[51] Reported savings estimates are net and are available from CEDARS (https://cedars.sound-data.com/).

[52] Equivalencies estimated using the EPA Greenhouse Gas Equivalencies Calculator (https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator).

Table 5.2: Savings and Expenditures from Non-Codes and Standards IOU Program[53]

Year	2021	2020	Grand Total
All Investor Owned Utilities			
Electric (GWh)	**434**	**720**	**1154**
Demand (MW)	**56**	**112**	**167**
Natural Gas (MMTh)	**26**	**46**	**72**
Carbon (1000 Tons CO2)	**263**	**519**	**782**
Total Expenditures ($M)	**$228**	**$407**	**$635**
PGE			
Electric (GWh)	256	370	**626**
Demand (MW)	51	62	**112**
Natural Gas (MMTh)	12	16	**28**
Carbon (1000 Tons CO2)	134	223	**357**
Total Expenditures ($M)	$87	$165	**$252**
SCE			
Electric (GWh)	139	267	**407**
Demand (MW)	4	37	**41**
Natural Gas (MMTh)	0	0	**0**
Carbon (1000 Tons CO2)	36	93	**129**
Total Expenditures ($M)	$60	$103	**$163**
SoCalGas			
Electric (GWh)	1	2	**3**
Demand (MW)	1	0	**1**
Natural Gas (MMTh)	14	28	**42**
Carbon (1000 Tons CO2)	81	165	**246**
Total Expenditures ($M)	$55	$91	**$146**
SDGE			
Electric (GWh)	37	80	**117**
Demand (MW)	0	13	**13**
Natural Gas (MMTh)	1	2	**2**
Carbon (1000 Tons CO2)	12	38	**50**
Total Expenditures ($M)	$25	$48	**$73**

[53] 2021 data does not include fourth quarter data which will be available May 1st, 2022; Savings data does not include REN/CCAs or Codes and Standards advocacy savings; Savings data is reported net, first-year savings; Data does not include Energy Savings Assistance Program savings and costs; IOU Expenditures are reported at the program level and are not broken down into gas vs. electric expenditures. The total EE budget for 2021 was $611 million.

Demand Response

Per D.17-12-003, Demand response is defined as "reductions, increases, or shifts in electricity consumption by customers in response to either economic signals or reliability signals." Effective demand response programs provide California ratepayers with various economic and environmental benefits, such as:

1) Saving ratepayer money by deferring capital expenditures to build power plants and transmission infrastructure that would otherwise be necessary to meet peak demand.
2) Decreasing the price of wholesale energy and avoiding the purchase of high-priced energy.
3) Providing greater reliability to the grid, which helps prevent blackouts.
4) Avoiding the consumption of fossil fuels which can reduce GHG emissions.

Evolution of Demand Response Programs

Demand Response (DR) goals are met through customer bill credits or payments to participate in DR programs or customers modifying their energy usage in response to dynamic rates.

Some DR programs operate with the use of dynamic pricing programs and time-variant rates in which price signals encourage customers to shift their energy use to off-peak periods of the day when energy demand is lower, such as time of use (TOU), critical peak pricing (CPP), peak time rebate (PTR), and real time pricing (RTP). Other demand response programs such as the Base Interruptible Program (BIP), Capacity Bidding Program (CBP), or Air Conditioning Cycling (A/C Cycling) are bid as a capacity resource into CAISO energy markets, enabling them to compete against generation bids and to be dispatched as needed by the CAISO.

DR programs were historically aimed at large commercial and industrial customers that can shed significant amounts of load as an immediate or day-ahead response. With the advent of smart meters, smart thermostats, batteries, and other smart devices, DR programs for residential customers were introduced and residential customer participation in DR has grown over time.

Future DR programs are expected to help integrate increasing amounts of renewable power onto the grid by shifting electric loads to periods of high renewable generation. There may also be a significant role for DR to alleviate electricity supply shortages in certain local areas of the state with constraints on transmission capacity.

Third Party Demand Response

Additionally, some DR programs are managed by third-party operators also known as "Demand Response Providers," (DRPs) which provide customers with additional choices beyond programs run by utilities. The addition of third-party operators as an alternative to utility DR programs stimulates competition to innovate and offer the best value.

The costs for DR programs include administration, incentives, marketing/customer education, measurement/evaluation, IT infrastructure, and pilots. One of the third-party programs, the Demand Response Auction Mechanism (DRAM) pilot, provides a pathway for third-party DR providers and their customers to receive resource adequacy-eligible capacity payments for providing load shedding services during periods of peak electricity demand and high prices. Under the DRAM pilot, utilities procure capacity through bids that include all costs except for utility technology incentives.

Pursuant to the 2019 DRAM decisions, the IOUs conducted DRAM auctions for 2020, 2021, and 2022 which procured 216 MW, 206 MW, and 201 MW (August capacity) for the respective years from third-party DRPs. Currently, Nexant Inc., a consultant, is conducting a follow up evaluation of the DRAM pilot. Their evaluation report is expected to be available in the second quarter of 2022.

As an alternative pathway to participate in DRAM, the CPUC established a Load Impact Protocol review process to qualify third-party DR providers to provide DR capacity for resource adequacy (RA) to non-IOU load serving entities (LSEs), such as community choice aggregators and energy service providers. Six DR providers applied, successfully completed the review process, and contracted upwards of 200 MW of RA-eligible DR capacity in 2022 to non-IOU LSEs.

Summer Reliability

In response to the August 2020 rotating outages, The Commission expanded the role of demand response resources to help address reliability concerns due to extreme weather.

- D.21-03-056 in Phase I of Summer Reliability proceeding established the Emergency Load Reduction Program (ELRP) as a pay-for-performance demand response program that compensates voluntary incremental load reduction provided by a participating customer during a program event triggered in response to CAISO declared grid emergencies. Participation in ELRP includes directly enrolled non-residential customers, virtual power plant aggregators, and customers with Rule 21 exporting DERs.

- D.21-12-015 in Phase II Summer Reliability proceeding increased the ELRP compensation rate to $2 per kWh of incremental load reduction achieved by the customer. Participation in ELPR is expanded to include non-residential aggregators, electric vehicle/charging station aggregators (including both V1G - vehicle charging and V2G - vehicle discharging into the grid) and directly enrolled residential customers.

- Additionally, the CPUC adopted several enhancements to IOU DR programs, expanded the smart thermostat program to fund about 300,000 new thermostats in hot climate zones, with the customer required to participate in a supply-side DR program, and directed PG&E and SCE to implement hourly dynamic rate pilots for agricultural water pumping and other end uses.

Customer Generation

Over the past several years, the CPUC has taken actions that support the development of customer-sited distributed energy resources and related technologies by providing financial incentives to customers and project developers. Ratepayers fund Distributed Generation (DG) programs that provide financial incentives to participating customers including the Disadvantaged Community 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) provides customer-generators with bill credits for power generated by their onsite systems that is fed back into the grid.

Table 5.3: 2021 GHG Auction Proceeds Funded Demand Side Management and Customer Programs ($000)[54]

	PG&E	SCE	SDG&E	Total
Disadvantaged Communities Single-Family Solar Homes, Green Tariff, Community Solar Green Tariff	10,840	7,131	1,030	**19,001**
Solar on Multifamily Affordable Housing[55]	56,920	63,966	16,743	**137,629**
Total	**67,760**	**71,097**	**17,773**	**156,630**

<u>Disadvantaged Communities Single-Family Solar Homes (DAC-SASH), Disadvantaged Communities-Green Tariff (DAC-GT), and Community Solar Green Tariff (CSGT) Programs</u>

AB 327 (Perea, 2013) required the Commission to develop "specific alternatives designed for growth [in adoption of renewable generation] among residential customers in disadvantaged communities." The Commission determined that installations under the Solar on Multifamily Affordable Housing (SOMAH) Program

[54] Table 5.3 shows the Demand Side Management paid for by IOUs GHG proceeds.

[55] Solar On Multifamily Affordable Housing (SOMAH) program includes current year funding and prior year true-up amounts. A SOMAH funding year cannot exceed $100M per D.17-12-022 and Public Utilities Code 2870. The amounts in in this table are more than $100M since it includes prior-year true-up amounts which are not subject to a given year's $100M cap.

(D. 17-12-022) should count towards the obligation to develop alternatives for DACs, but also recognized the need to develop multiple programs and tariff options to address the variety of barriers that residents of disadvantaged communities face in accessing renewable energy. Thus, D.18-06-027, adopted in June 2018, established three additional programs to provide households in DACs access to renewable energy: two rate programs (the DAC-Green Tariff (DAC-GT) and the Community Solar Green Tariff (CSGT) programs) and a direct-install solar program, the DAC Single-family Solar Homes (DAC-SASH) program. For these programs, DACs are defined as communities identified by CalEnviroScreen 4.0 as among the top 25 percent most impacted communities statewide, in addition to 22 census tracts in the highest 5 percent of CalEnviroScreen's Pollution Burden that do not have an overall score in the top 25 percent. In December 2020, the Commission voted to expand the DAC-SASH program's definition of DACs to include California Indian Country.

DAC-SASH provides incentives for income-qualified, single-family homeowners who live in DACs to install solar on their roof. Modeled after the existing SASH program, DAC-SASH has a budget of $10 million per year through 2030. A DAC-SASH Handbook developed by the selected statewide Program Administrator, GRID Alternatives, was approved by the Commission in September 2019. To date, DAC-SASH has helped install 1,018 rooftop solar systems, totaling 4.15 MWs.

DAC-GT enables income-qualified, residential customers in DACs who may be unable to install solar on their roof to benefit from utility scale clean energy and receive a 20 percent bill discount. The program is modeled after the existing Green Tariff portion of the Green Tariff/Shared Renewables Programs and is available to customers who meet the income eligibility requirements for the CARE and FERA programs. The program has a capacity cap of 158 MWs and has enrolled approximately 20,000 customers to date.

CSGT enables residential customers in DACs who may be unable to install solar on their roof to benefit from a local solar project and receive a 20 percent bill discount. The communities work with a local non-profit or government "sponsor" to organize community interest and present siting locations to the utility or CCA; the sponsor can also receive an incentive for its efforts. The program has a capacity cap of 41 MWs and is anticipated to begin enrolling customers in late 2022.

Solar on Multifamily Affordable Housing (SOMAH) Program

AB 693 (2015) directed the CPUC to develop a program that provides financial incentives for the installation of solar energy photovoltaic (PV) systems on multifamily affordable housing properties throughout California. The CPUC issued D.17-12-022 that outlined the program design for the new SOMAH program in the service territories of PG&E, SCE, SDG&E, Liberty Utilities, and PacifiCorp. In addition to building on many of the program successes and lessons learned from the CSI-funded MASH Program, the SOMAH program seeks to:

- Direct up to $100 million annually from the electric IOUs' Greenhouse Gas Auction Proceeds towards subsidized solar energy systems on multifamily affordable housing.

- Encourage the development and installation of solar systems in California's disadvantaged and low-income communities.

- Develop, by December 31, 2030, at least 300 MW of installed solar generating capacity.

The SOMAH Program opened on July 1, 2019, with more than 200 applications received on day one, and waitlists were started in the PG&E, SCE, and SDG&E service territories which have since been cleared. The SOMAH Program Administrator continues to develop and implement strategies to ensure a robust pipeline of applications. A recent program evaluation, completed October 2021, made recommendations for the SOMAH Program Administrator including streamlining the application process and providing additional support to contractors and property owners on how to meet its equity and other requirements.[56] In April 2020, the CPUC issued D.20-04-012, which allocated additional funds to the program until June 30, 2026. As of January 2022, the program has 461 active applications, with nearly 34 percent of these in disadvantaged communities. There are 14 completed projects with half in disadvantaged communities, and these projects in total received approximately $4.9 million in incentives. For completed projects, the average system size was 197.8 kW and were given an average incentive of $347,000. Active applications and completed projects together equaled 82.1 MW, or 27 percent of the way to the program's 300 MW goal.

Self-Generation Incentive Program (SGIP)

Established in 2001, SGIP provides incentives to support distributed energy resources that will result in reductions in GHG emissions and peak demand. SGIP is one of the longest-running DG incentive programs in the country. Since the program's inception, over $2.5 billion in SGIP incentives have been paid out or reserved to over 45,000 projects comprising almost 1.7 gigawatts of capacity. In 2021, almost $300 million was paid out or reserved to over 12,000 projects comprising 206 MW of capacity; all but $5.4 million went to energy storage systems.

- The program was reauthorized by SB 700 (2018) to continue ratepayer collections through 2024 and program administration through 2026. Pursuant to SB 700, the CPUC authorized ratepayer collections of $166 million annually for the years 2020 to 2024 in D.20-01-021 for a total of $830 million. The program funds are collected from PG&E, SCE, SDG&E, and SoCalGas.

- CPUC D.20-01-021 allocated the $830 million authorized in new ratepayer collections across the SGIP budget categories: 88 percent to energy storage

[56] SOMAH Phase 2 Program Evaluation by Verdant Associates, October 2021, can be accessed here: somah_phaseii_report_20211013_final.pdf (ca.gov)

and 12 percent to renewable generation. Within energy storage, an additional $512 million was allocated to the equity resiliency budget created in D.19-09-027. This budget provides the highest incentive level to vulnerable households and facilities that support vulnerable communities to enable these groups to enhance their resiliency in the face of wildfire risks and related de-energization events.

- CPUC D.21-12-031 allocated almost $67 million of unused accumulated funds to fund the waitlists in the respective SGIP Program Administrator service territories. Priority was given to Equity Resiliency Budget projects. Across the four SGIP Program Administrators, over 335 projects were funded from the waitlists.

- Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells and advanced energy storage systems. For non-residential systems, half of the incentive is paid up-front and half of the incentive is paid based on the performance of the technology over five years.

Net Energy Metering (NEM)

California's net energy metering (NEM) program allows customers who install eligible renewable electrical generation facilities to serve onsite energy needs and receive credits on their electric bills for surplus energy sent to the electric grid. NEM customers pay for their cost to connect to the grid, take service on a "time-of-use" rate plan, and pay "non-bypassable" charges that cannot be offset with surplus energy credits in order to contribute their fair share toward public purpose programs and other initiatives. Unlike the other programs in this section, the costs associated with NEM come from the intra-rate class cost shift (from NEM customers to non-NEM customers) rather than program costs. Because retail rates include cost recovery for system costs that cannot be avoided by distributed generation, NEM bill credits for customer-generators result in a revenue shortfall that must be recovered through increased rates for residential and commercial customers who do not participate in the program.

In January 2016, the CPUC approved a decision adopting a NEM successor tariff (NEM 2.0) for customers receiving NEM service after each utility reached its 5 percent NEM capacity cap. The NEM 2.0 program went into effect in SDG&E's territory in June 2016, in PG&E's territory in December 2016, and in SCE's territory in July 2017. Customers on NEM 2.0 must pay an interconnection fee and pay non-bypassable charges on each kWh of energy they consume from the grid within a metered interval and take service on a time-of-use rate.[57] In its 2016 decision (D.16-01-044), the CPUC

[57] For purposes of the NEM successor tariff, the relevant non-bypassable charges are: Public Purpose Program Charge; Nuclear Decommissioning Charge; Competition Transition Charge; and Department of Water Resources bond charges.

stated its intention to later revisit the NEM successor tariff, with a view to considering adjustments after gaining better visibility into how residential rate reform and the CPUC's DRP and IDER proceedings developed.

In December 2019, Verdant Associates,[58] Energy and Environmental Economics, Inc. (E3), and ILLUME Advising were chosen to conduct an independent evaluation of NEM 2.0. ILLUME conducted an evaluation of the California Solar Consumer Protection Guide and recommended improvements that the CPUC then made in September 2020.

Verdant, with the assistance of E3, analyzed the costs and benefits to both customers and utilities of customer-sited renewable resources taking service on NEM 2.0.[59] It found that the tariff is cost-effective overall for NEM 2.0 participants but is not cost-effective from a combined participant/utility perspective or for non-participating ratepayers.[60] The study also compared the cost for the utility to serve NEM 2.0 customers—based on the customer's grid usage and fixed costs of service—against their total bill payments. It found that prior to NEM 2.0 system installation, both residential and nonresidential NEM 2.0 customers pay more in their utility bills than their estimated costs of service, on average. Post-installation, the average residential customer pays less, and the average nonresidential customer pays more, than the estimated utility cost to serve them.[61] Verdant finalized the report in January 2021.

In August 2020, the CPUC opened a proceeding, Rulemaking (R.) 20-08-020, to revisit the NEM successor tariff. A primary goal of the proceeding is to incorporate information that has become available since 2016 to enable California's compensation program for customer-generators to better fulfill its AB 327 (2013) statutory requirements. In addition to the NEM 2.0 evaluation, the proceeding has referenced a white paper on possible compensation mechanisms for customer-generators that can meet the statutory requirements for the NEM program, authored by E3. Parties to the proceeding filed proposals for a successor to the current NEM program as well as subsequent filings to develop the evidentiary record of the proceeding. A proposed decision describing a new net billing tariff was issued on December 13, 2021. The proposed decision found that NEM shifts costs from wealthier-than-average NEM customers onto less-wealthy-than-average non-NEM customers, which has become a rapidly accelerating problem threatening the CPUC's equity and electrification goals. The proposed decision's changes apply primarily to new customers and seek to reduce (though not fully

[58] The contract was originally awarded to Itron and was transferred to Verdant Associates in Summer 2020.

[59] The draft and final reports are available at https://www.cpuc.ca.gov/nem2evaluation.

[60] The draft report found that NEM 2.0 is cost-effective from a combined participant/utility perspective due to a modeling error, but we report the final report's findings above for clarity on the conclusions that should be taken away.

[61] The study also provided analysis, not summarized here, regarding customers' energy usage before and after installing renewable energy generation systems on the NEM 2.0 tariff, effects on cost-effectiveness of the addition of energy storage or the removal of the federal investment tax credit, cost-effectiveness compared to NEM 1.0, characteristics of the NEM 2.0 participant and non-participant populations, and other topics.

eliminate) the cost shift. The PD also promotes battery storage, seeks to reduce greenhouse gas emissions by reducing demand and increasing exports during peak grid demand periods, and creates an equity fund to encourage deployment of distributed energy resources by customers in low-income, disadvantaged, and tribal communities. The proposed decision had not been voted on at the time of writing.

Low-Income Programs

In addition to programs serving low-income customers and customers residing in DACs mentioned previously, the IOUs provide three ratepayer-funded energy assistance programs for qualifying low-income customers. The California Alternate Rates for Energy program (CARE) offers bill discounts off energy bills for low-income customers. The Family Electric Rate Assistance (FERA) program provides families of three or more, whose household income slightly exceeds the CARE allowances, with an 18 percent discount on their electricity bill. The Energy Savings Assistance program (ESA) provides no-cost in-home weatherization services, energy efficiency measures, and energy education to help eligible low-income households conserve energy, reduce energy costs and improve their health, comfort, and safety. The Energy Savings Assistance Common Area Measures (ESA CAM) program provides no-cost energy efficiency measures for income qualifying deed restricted multifamily properties.

California Alternate Rates for Energy (CARE)

The CARE program is a low-income energy rate assistance program that provides a discount on energy bills to qualifying low-income households. CARE is funded by non-exempt customers (exempt customers include CARE customers) as part of a statutory "public purpose program surcharge" that appears on monthly utility bills. The income qualifications for the CARE program are households that are at or below 200 percent of the Federal Poverty Guidelines.

The program was established in 1989 by California Public Utilities Code Sections 739.1 and 739.2, authorizing a 15 percent rate discount for qualifying low-income customers off their energy bills. In 2001, the minimum CARE rate discount was increased from 15 percent to 20 percent by CPUC D.01-06-010. However, due to a number of factors on how rate increases and new charges were allocated to customers, the effective discounts grew to over 40 percent for some CARE customers.

In October 2013, AB 327 was passed requiring the IOUs to restructure the CARE discount rates and to set an effective electric rate discount between 30-35 percent. In compliance with AB 327 and D.15-07-001, the effective discounts have been reduced to 35 percent for PG&E and SDG&E, and will remain at 32.5 percent for SCE. These reductions occurred gradually to prevent rate shock.

As economic hardships for California residents have increased over the course of the COVID-19 pandemic, participation in CARE has increased with approximately one million new customer accounts added between March and December 2020 and an additional 760,000 new accounts in 2021. In 2021, the program provided approximately $1.9 billion in annual subsidies and served approximately 5 million low income customers statewide.[62] A higher CARE subsidy does not result in a higher revenue requirement for the utility, but it does increase the rates that non-CARE customers pay. Even for these customers though, the CARE program surcharge has long been a small percentage of their energy bill. For example, in 2020, the CARE surcharge on a non-CARE residential monthly electric bill ranged from 2 percent to 4 percent of the total bill, which translates to an average of $3 to $4 a month. Similarly for residential gas bills, the CARE surcharge on a non-CARE residential monthly gas bill was about 2 percent of the total bill, which equals around $2 a month.[63]

PG&E's CARE subsidy in 2021 was approximately $904 million, compared to $618 million for SCE, $175 million for SDG&E, and $178 million for SoCalGas (see **Table 5.3**).

Table 5.4 2021 CARE Program Costs[64]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$747,584,506	$9,110,630	$756,695,137
	Gas	$156,023,717	$2,277,658	$158,301,375
SCE	Electric	$617,958,047	$5,669,293	$623,627,340
SDG&E	Electric	$154,978,964	$3,966,281	$158,945,245
	Gas	$19,845,896	$536,828	$20,382,724
SoCalGas	Gas	$178,416,136	$7,800,126	$186,216,262
Total		**$1,874,807,267**	**$29,360,817**	**$1,904,168,083**

Energy Savings Assistance Program (ESA)[65]

The ESA program is a no-cost energy efficiency program that provides home weatherization services and energy efficiency measures to help low income households conserve energy, reduce their energy costs/utility bills, and improve the health, comfort, and safety of the home. The program also provides information and education to promote energy efficient practices in low income communities. Additionally, the ESA program has a multifamily component addressing building wide common areas (ESA CAM), providing energy efficiency measures for deed restricted properties. ESA is funded by all utility customers as part of a statutory "public purpose program surcharge" that appears on monthly utility bills.

Currently, the income qualifications for the ESA program are households that are at or below 200 percent the Federal Poverty Guidelines. However, in 2021, the California legislature adopted Senate Bill 756 which increased the ESA program income eligibility.

[62] Some customers are enrolled in more than one program, for example SCE for electricity and SoCalGas for natural gas. Source: 2021 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

[63] Source: 2020 Investor-Owned Utility ESA-CARE Annual Reports, posted to Docket A.14-11-007.

[64] Source: 2021 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003.

[65] Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

Effective July 2022, households at or below 250 percent of Federal Poverty Guidelines are eligible for the program, thereby expanding the program to a greater number of California low-income households.

The program's original objective was to promote equity and relieve low-income customers of the burden of rising energy prices. The program has evolved into a resource program that achieves energy savings while improving quality of life for low-income customers.

The CPUC initiated the first energy efficiency programs for low-income customers in the early 1980s. In 1990, the California legislature adopted and codified the ESA program in Public Utilities Code Section 2790(a) requiring the electrical and gas corporations to perform home weatherization services for low-income customers in their service territory, taking into consideration both the cost-effectiveness of the services and the policy of reducing hardships for low-income households. In 2007, the CPUC adopted a programmatic initiative in D.07-12-051 to provide all eligible customers the opportunity to participate in the ESA program and to offer participants with cost-effective energy efficiency measures in their residences by 2020. Public Utilities Code Section 382(e) codified this goal so that, by the end of 2020, all eligible and willing low-income customers would have the opportunity to participate in the ESA program. The IOUs largely met this goal.

In June 2021, CPUC issued D.21-06-015 to set ESA budgets and program designs for program years 2021 to 2026. This decision moves away from setting ESA program goals based on number of households treated and towards deeper energy savings goals. This new, customer-centric paradigm focuses on achieving deeper energy savings at the household level and encourages IOUs to prioritize ESA treatments for vulnerable customers (for example, households with arrearages, high energy usage, or those living in DACs).

Customers enroll in the ESA program through various channels including leads from CARE program participants, door-to-door neighborhood canvasing, direct mail, email, community-based organizations, categorical enrollment, online, and community events. Marketing materials are available in multiple languages. ESA is an income-verified program; however, customers can enroll automatically if already participating in another financial assistance programs with similar criteria. **Table 5.4** shows the 2021 ESA program costs. In 2021, ESA served approximately 327,269 households (ten percent received energy education only), achieved 103 GWh and 0.86 MMtherms of annual energy savings.[66] In 2021, the ESA CAM program served 238 properties which together

[66] The number of households treated was reduced by 10 percent as a placeholder to account for households treated in shared IOU-territories. Final household treatment numbers will be available in IOU Annual Reports for Program Year 2021 on May 1, 2022.

contain nearly 14,000 units and achieved annual energy savings of 8.2 GWh and 0.16 MMtherms.[67]

Table 5.5: 2021 ESA Program Costs[68]

Utility	Operations	ESA Year-To-Date Expenses 2021	ESA CAM Year-To-Date Expenses 2021*
PG&E	Electric and Gas	$155,587,605	$15,870,397
SCE	Electric	$70,392,875	$914,169
SDG&E	Electric and Gas	$14,734,902	$1,472,402
SoCalGas	Gas	$109,303,988	$1,444,936
Total		**$350,019,370**	**$19,701,904**

*ESA CAM is not a part of the investor-owned utilities' total revenue requirement as it is funded by previously unspent ESA Funds by D.16-11-022, modified by D.17-12-009.

Family Electric Rate Assistance (FERA)

The FERA program is a low-income electric rate assistance program that provides an 18 percent discount on electric bills to qualifying low-income households with three or more individuals. FERA is funded by a statutory "public purpose program surcharge" that appears on monthly utility bills. The FERA program was designed to assist large families that are ineligible for the California Alternate Rates for Energy (CARE) rate because their income levels are slightly above the CARE program limits.

The income limits of the FERA program range from 200 percent plus $1 to 250 percent of the Federal Poverty Guidelines. Public Utilities Code Section 739.1(f)(2) requires a single application form for CARE and FERA to enable applicants to apply for the appropriate assistance program based upon their level of income and economic need.

The FERA program was established in 2004 by CPUC D.04-02-057 as the Lower Middle Income Large Household program. In D.05-10-044, the lower income limits of the FERA program were raised to 200 percent plus $1 of the Federal Poverty Guideline levels, which correspond to the upper limits of the CARE program. In compliance with Senate Bill 1135 (Bradford, 2018) and California Public Utilities Code §739.12, the FERA program discount increased from 12 percent to 18 percent effective January 1, 2019.

D.21-06-015 established a 50 percent enrollment goal by 2023 and a 70 percent enrollment goal by 2026. The decision also approved FERA dedicated program

[67] Source: 2021 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.19-11-003. Final property, unit, and energy savings numbers will be available in IOU Annual Reports for Program Year 2021 on May 1, 2022.

[68] Source: 2021 Investor-Owned Utility ESA-CARE Monthly Reports, posted to Docket A.14-11-007.

management budgets, and directed the utilities to create tailored marketing and outreach efforts to reach these program enrollment goals. PG&E's FERA subsidy in 2021 was approximately $14.68 million, compared to $12.67 million for SCE, and $4.04 million for SDG&E. At the end of 2021, approximately 80,720 households were enrolled in FERA out of an estimated 400,000 eligible households.[69] **Table 5.5** shows the 2021 FERA program costs.

Table 5.6: 2021 FERA Program Costs[70]

Utility	Operations	Subsidy	Administrative Costs	Total
PG&E	Electric	$14,681,075	$2,266,517	$16,947,591
SCE	Electric	$12,674,500	$622,683	$13,297,183
SDG&E	Electric	$4,042,216	$247,959	$4,290,175
Total		**$31,397,790**	**$3,137,159**	**$34,534,949**

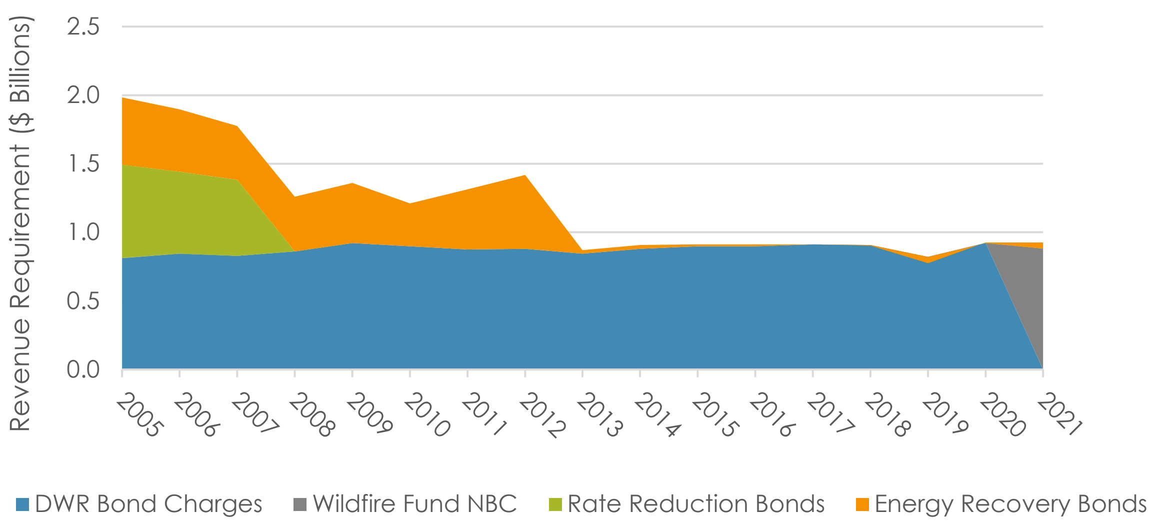
[69] Source: Energy Division Data Request. Final FERA program enrollment for 2021 will be available in IOU Annual Reports for Program Year 2021 on May 1, 2022.

[70] Source: Energy Division Data Request. Final FERA program costs for 2021 will be available in IOU Annual Reports for Program Year 2021 on May 1, 2022.

VI. Bonds, Regulatory Fees, and Legislative Program Costs

During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis of 2000-2001. Since the energy crisis, these bond costs have decreased from a peak of approximately $2 billion in 2005 to approximately $900 million in 2020 and then were retired in 2021. In 2021, the bond charges were replaced by the Wildfire Fund Non-Bypassable Charge of $882 million, as illustrated in **Figure 6.1**.

Figure 6.1: Trends in Bond and Wildfire Fund Expenses ($ Billions)



Rate Reduction Bonds were issued in 1998 and paid back in full in 2007. AB 1890, the legislation that established the terms of energy restructuring, authorized these bonds to provide an immediate reduction in electric rates. Among other things, the legislation froze electric rates at June 1996 levels and reduced rates for residential and small commercial customers by 10 percent.

DWR bonds were issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis. As of September 30, 2020, enough funds were collected from ratepayers to retire the DWR bonds, and consequently the DWR bond charge expired.

On October 1, 2020, pursuant to AB 1054 (2019) and CPUC Decision (D.) 19-10-056, the Wildfire Fund Non-Bypassable Charge (NBC) was implemented.[71] The 2020 Wildfire Fund NBC was equivalent to the expired DWR bond charge, and was identical in 2021, resulting in no 2021 bill increase to customers. The Wildfire Fund NBC supports the participation of large electrical utilities in the AB 1054 Wildfire Fund.

In addition, AB 1054 codified Public Utilities Code (PUC) section 8386.3(e), which authorizes the CPUC to issue a financing order allowing IOUs to issue recovery bonds to finance the first $5 billion of approved wildfire mitigation capital expenditures in aggregate among the three large electric IOUs. This program effectively saves ratepayers money by allowing lower cost financing compared to traditional utility financing mechanisms.

In A.20-07-008, Southern California Edison (SCE) sought authority to implement a fixed recovery charge and issue recovery bonds to finance $327 million of Grid Safety and Resiliency Program (GSRP) capital expenditures. D.20-11-007 granted SCE's request and the related fixed recovery charges financing the GSRP were implemented beginning in 2021. The AB 1054 bond charges for SCE ($19.04 million in 2021) appear in **Table 6.1** under the category Other Regulatory.

Similarly, pursuant to AB 1054, PG&E filed Application (A.) 21-02-020 requesting authority to implement a fixed recovery charge and issue recovery bonds to finance up to $1.2 billion of approved wildfire mitigation capital expenditures. D.21-06-030 approved PG&E's request which ultimately resulted in a securitization bond issuance totaling $860 million. The related fixed recovery charges were implemented effective December 1, 2021, and the related costs will be reported next year.

As part of the CPUC and PG&E bankruptcy settlement agreement reached after PG&E's first bankruptcy in 2001, the utility was authorized to recover $2.2 billion as a Regulatory Asset. This was a separate and additional part of PG&E's rate base. The Energy Recovery Bonds were issued by PG&E in 2003 to reduce the financing cost of the Regulatory Asset to ratepayers.

Table 6.1 shows the bond expenses component of the 2021 revenue requirement for each of the electric IOUs.

[71] CPUC D.19-10-056, October 24, 2019, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M318/K549/318549782.pdf.

Table 6.1: 2021 Bond Expenses ($000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges	0	0	0	0
Rate Reduction Bonds	0	0	0	0
Energy Recovery Bonds	24,387		0	24,387
Wildfire Fund NBC	403,357	388,714	90,159	882,229
Other Regulatory	0	19,040	0	19,040
Total	**427,744**	**407,754**	**90,159**	**925,657**

Fees and Incentives

Fees include a variety of charges levied by federal, state, and local governments. For example, the CPUC fee reimburses the State for the cost of regulating the utilities. Incentives offer a financial inducement for utilities to achieve certain policy goals that may not be effectively accomplished only through regulatory directives. **Table 6.2** shows the 2021 revenue requirement for regulatory fees. In total, this entire category of expenses accounted for roughly five percent of the 2021 revenue requirement. Some fees are included in the other revenue components. Only nuclear decommissioning costs are recovered separately through the Nuclear Decommissioning Adjustment Mechanism.

Table 6.2: 2021 Regulatory Fees and Incentives ($000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC Reimbursement Fee[1]	100,348	100,183	0	200,531
Franchise Fee & Uncollectible Surcharge[2]	0	8,283	4,494	12,778
Catastrophic Events Memo Account[3]	128,139	82,373	0	210,512
Hazardous Substance Mechanism	35,480	0	80	35,560
Nuclear Decommissioning[4]	78,836	(47,539)	192	31,489
Spent Nuclear Fuel	0	4,481	1,060	5,541
Major Emergency Balancing Account[5]	89,594	0	0	89,594
Wildfire Mitigation Plan Memo Account[6]	161,463	0	0	161,463
Fire Risk Mitigation Memo Account[7]	32,913	0	0	32,913
Total	**626,773**	**147,780**	**5,826**	**780,380**

1. SDG&E did not include the CPUC fee in the revenue requirements reported here; however, SDG&E did include the CPUC fees in revenue requirements reported for the Legislative Program Costs section below (see Table 6.3). The 2021 electric CPUC reimbursement fees for PG&E, SCE, and SDG&E were $0.00130/kWh.
2. Not reported elsewhere.
3. SDG&E funds recorded in CEMA were not authorized to be collected in 2021.
4. Includes Nuclear Decommission franchise fees and uncollectible expense as applicable.
5. For SCE and SDG&E, forecasts for emergency preparedness and response are approved as part of the GRC budget and not in a segregated balancing account.
6. SCE and SDG&E have not collected revenue for Wildfire Mitigation Plan Memo Account.
7. SCE and SDG&E have not collected revenue for Fire Risk Mitigation Memo Account.

Definition of Fees

- **CPUC Reimbursement Fee:** This is the annual fee to be paid by utilities to fund their regulation by the CPUC (California Public Utilities (PU) Code 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.
- **Franchise Fees:** 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. These fees are then redistributed to the cities and counties. In some cases, these fees are included in other cost categories and not separately determined in this report, as appears to be the case with PG&E.[72]
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected. There are large pending, uncollectible balances from COVID-19 related accounts that were not in rates in 2021. These will be partially offset with California Arrearage Payment Program (CAPP) from the State and will be reported in next year's AB 67 Annual Report.

[72] PG&E reported $0 for franchise fees in 2021 and in several other year's past, suggesting that they may have been reported in other cost categories after recovery in surcharges, and not recorded here.

- **Catastrophic Events Memorandum Account (CEMA)**: An account established to enable a utility to recover the costs associated with the restoration of service and utility facilities affected by a catastrophic event (e.g., an earthquake) or state of emergency declared by federal or state authorities.
- **Hazardous Substance Mechanism:** An account established to allow certain costs of investigating and remediating hazardous waste sites identified by the utilities.
- **Nuclear Decommissioning:** Nuclear decommissioning funds are established for the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Spent nuclear fuel is shown as a separate item.
- **Major Emergency Balancing Account:** Specific to PG&E, the MEBA recovers actual costs resulting from responding to major emergencies and catastrophic events not eligible for recovery through the CEMA. In some cases, costs relating to major emergencies that are found by the CPUC not to be eligible for recovery through the CEMA process may be recoverable through the MEBA.
- **Wildfire Mitigation Plan Memorandum Account:** In 2019, pursuant to SB 901 (2018), each electric utility opened an account to track its costs incurred to implement its annual wildfire mitigation plan and seek recovery at a later date. With the exception of SDG&E, the utilities (PG&E[73] and SCE[74]) have submitted applications to recover the costs recorded in this account.
- **Fire Risk Mitigation Memorandum Account:** In 2019, pursuant to SB 901 (2018), each electric utility was allowed to establish an account to enable it to track its costs incurred for fire risk mitigation that are not otherwise covered in the electric revenue requirement, and seek recovery at a later date. With the exception of SDG&E, the utilities (PG&E[75] and SCE[76]) have submitted applications to recover the costs recorded in this account.

Legislative Program Costs

Various electric programs, operated by the IOUs, are mandated by the State of California. Most programs aim to provide California with clean energy, while some programs provide cost shifts or subsidies to various customer groups. Some bonds and regulatory fees may also be mandated by the State. **Table 6.3** shows the 2021 electric revenue requirement for the legislative mandates.

[73] In CPUC D.20-10-026, PG&E was authorized to recover partial revenue for its Wildfire Mitigation Plan Memorandum Account from December 2020 through April 2022.

[74] In CPUC D.21-01-012 and D.21-10-25, SCE was authorized to recover partial revenue for its Wildfire Mitigation Plan Memorandum Account begining on March 1, 2022.

[75] In CPUC D.20-10-026, PG&E was authorized to recover partial revenue for its Fire Risk Mitigation Memorandum Account from December 2020 through April 2022.

[76] In CPUC D.21-01-012 and D.21-10-25, SCE was authorized to recover partial revenue for its Fire Risk Mitigation Memorandum Account begining on March 1, 2022.

Table 6.3: 2021 California Mandated Programs Revenue Requirement ($000)

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Aliso Canyon Energy Storage	AB 2514	0	9,490	0	**9,490**
Bioenergy Market Adjusting Tariff Non-Bypassable Charge	SB 860, SB 1122	0	9,531	0	**9,531**
California Energy Systems for 21st Century	SB 96	0	0	(334)	**(334)**
California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	SB 1, AB 217, AB 2723	7,955	0	0	**7,955**
CPUC Fee	Public Utilities Code § 431-432	100,348	100,183	22,236	**222,767**
Demand Response [77]	SB 1414, AB 793	67,226	42,878	15,443	**125,547**
Disadvantaged Communities - Single-Family Affordable Solar Homes, Green-Tariff, Community Solar Green Tariff	AB 327	10,840	7,131	1,030	**19,001**
Electric Program Investment Charge/New Solar Homes Partnership Program	Public Utilities Code § 399.8, AB 1890, SB 1, AB X1 15	51,378	61,520	12,096	**124,994**
Energy Efficiency	SB 350, AB 1330, AB 802, AB 32, AB 1890, AB 841	174,355	123,058	47,533	**344,946**
Energy Savings Assistance Program/California Alternate Rates for Energy Program Administrative Expense	Public Utilities Code § 2790, § 382, AB 327, AB 2857, SB 580, AB 2140	176,631	6,608	130,134	**313,373**
Family Electric Rate Assistance[78]	SB 987, SB 1135	10,992	0	4,129	**15,121**
Green Tariff Shared Renewables	SB 43	12,872	2,148	0	**15,020**
Greenhouse Gas Cost[79]	AB 32	76,887	302,970	53,415	**433,272**
Greenhouse Gas Revenue Return	AB 32	(270,160)	(330,882)	(95,193)	**(696,235)**
Hazardous Substance Memorandum Account	AB X1 6	35,480	2,070	83	**37,633**

[77] Demand Response includes Demand Response Auction Mechanism and IDSM, as applicable.

[78] Family Electric Rate Assistance includes administrative expenses, as applicable.

[79] PG&E's Greenhouse Gas Cost is presented as a five-year average.

Program Name	Legislation	PG&E	SCE	SDG&E	Total
Mobile Home Park Program	Public Utilities Code § 2791-2799	26,406	11,921	7,148	**45,475**
Net Energy Metering[80]	AB 1070	409	0	286	**695**
Renewable Portfolio Standard[81]	SB 1078, SB 350, SB 100	2,091,632	2,467,316	599,577	**5,158,525**
San Diego Unified Port District	AB 628	0	0	2,894	**2,894**
San Joaquin Valley Disadvantaged Communities Pilot and Data Gathering	AB 2672	13,863	1,407	0	**15,270**
School Energy Efficiency Stimulus Program	AB 841	77,581	100,699	40,868	**219,148**
Self-Generation Incentive Program	AB 970, SB 700, AB 1144	59,851	56,637	20,069	**136,557**
Solar on Multifamily Affordable Housing	AB 693	56,920	63,966	16,743	**137,629**
Statewide Marketing Program	AB 793	10,415	8,078	0	**18,493**
Total Rate Adjustment Component	AB 1X	0	0	80,000	**80,000**
Transportation Electrification Programs[82]	SB 350, AB 1082, AB 1083, AB 676	22,750	25,119	26,482	**74,351**
Tree Mortality Non-Bypassable Charge	SB 859	65,988	62,987	16,822	**145,797**
Wildfire Fund Non-Bypassable Charge	AB 1054	403,357	412,395	90,159	**905,911**
Total		**3,283,976**	**3,547,230**	**1,091,620**	**7,922,826**

[80] Net Energy Metering includes solar system contracts and disclosures, as applicable.

[81] RPS revenue requirements do not distinguish the above-market portion. PG&E's RPS value is presented as a five-year average.

[82] Transportation Electrification includes pilots, as applicable.

VII. 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 may be categorized into the following 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 (PPP).

Unlike its process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Utilities procure gas supplies for core gas customers (primarily residential and small commercial) only. Utilities' gas procurement is subject to a sharing incentive under which utilities receive a reward if they procure gas at costs below certain benchmarks and incur a penalty if procured at costs above the benchmarks. The mechanism provides utilities with a financial incentive to purchase gas for core ratepayers at costs that are beneficial to the utility, with part of the savings being shared with ratepayers. Procurement costs shown in this report pertain to these core customers. Large volume noncore customers, such as industrial or electric generation, procure their own gas supplies and, therefore, procurement costs of their gas usage are not included herein. Core gas procurement costs are recovered in utility gas procurement rates, which are adjusted monthly. The commodity gas price is the cost component with the greatest variability. Monthly changes in gas commodity prices on customer bills provide consumers with immediate price signals that they can use to adjust their gas usage. The tables below show costs for 2021 and a comparison of 2021 to prior years.

Table 7.1 shows the 2021 natural gas revenue requirement by components.

Table 7.1: 2021 Gas Revenue Requirement by Key Components ($000)

	PG&E	SDG&E	SoCalGas	Total
Core Procurement	865,924	192,212	1,417,147	2,475,283
Transportation	3,783,288	585,603	3,896,051	8,264,942
Public Purpose Programs	277,667	28,663	324,052	630,382
TOTAL	**4,926,878**	**806,478**	**5,637,250**	**11,370,607**

Table 7.2 shows historical revenue requirement for 2015-2021 for the key components.

Table 7.2: Historical Gas Utility Revenue Requirement ($000) (2015-2021)

	2015	2016	2017	2018	2019	2020	2021
Core Procurement	2,380,796	2,053,769	2,465,182	2,067,169	2,226,842	1,822,180	2,475,283
Transportation	5,390,916	6,753,286	6,275,397	6,458,407	7,418,647	7,869,039	8,264,942
Public Purpose Programs	670,067	639,808	647,260	604,622	650,968	575,600	630,382
Total	**8,441,779**	**9,446,863**	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**

As **Table 7.2** shows, the 2021 total natural gas utility costs increased by 10.8 percent from 2020 compared to the 0.3 percent decrease for 2019-2020.

Figure 7.1 show the trends in natural gas utility revenue requirements by components.

Figure 7.1: Historical Trends in Gas Utility Revenue Requirement Components ($ Billions)

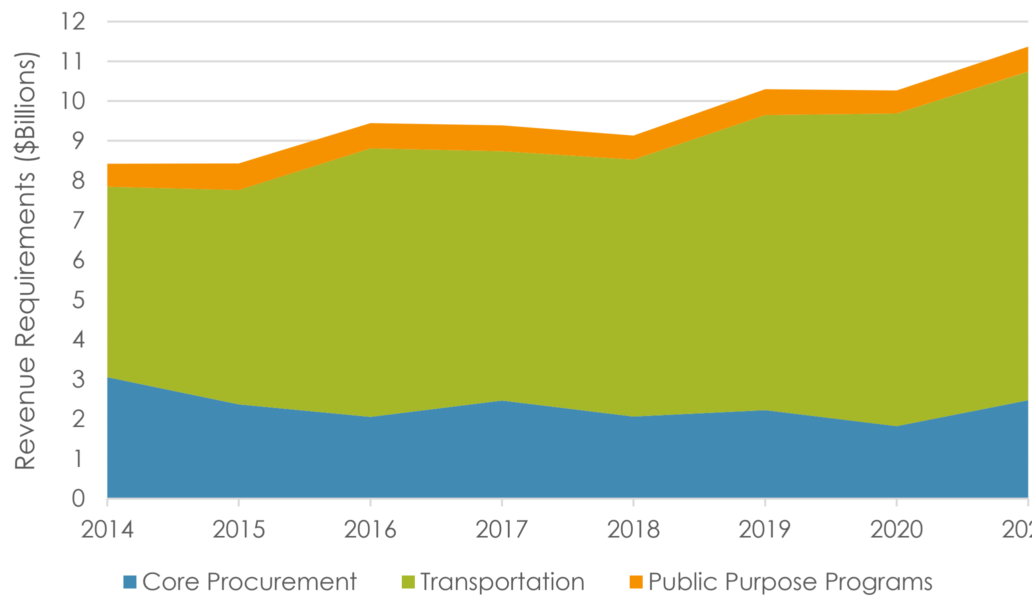


Table 7.3 shows the trends in natural gas revenue requirement for each of the utilities.

Table 7.3: Historical Revenue Requirement ($000)

	2015	2016	2017	2018	2019	2020	2021
PG&E	4,071,409	4,789,682	4,610,816	4,470,985	4,587,569	4,484,635	4,926,879
SoCalGas	3,826,574	4,095,158	4,191,353	4,113,388	5,042,690	5,009,906	5,637,250
SDG&E	543,796	562,023	585,670	545,825	666,198	772,278	806,478
Total	**8,441,779**	**9,446,863**	**9,387,839**	**9,130,198**	**10,296,457**	**10,266,819**	**11,370,607**

As **Table 7.3** shows , compared to 2020, PG&E's total natural gas utility costs in 2021 increased by 9.9 percent, SoCalGas' costs increased by 12.5 percent, and SDG&E's costs increased by 4.4 percent.

Changes in the components of revenue requirement are summarized below and discussed in more detail in their respective sections.

Compared to 2020, PG&E's revenue requirement in 2021 increased by 9.9 percent. For SoCalGas and SDG&E, revenue requirement in 2021 increased by 12.5 percent and 4.4 percent, respectively. Both SoCalGas and SDG&E saw a large increase in core procurement.

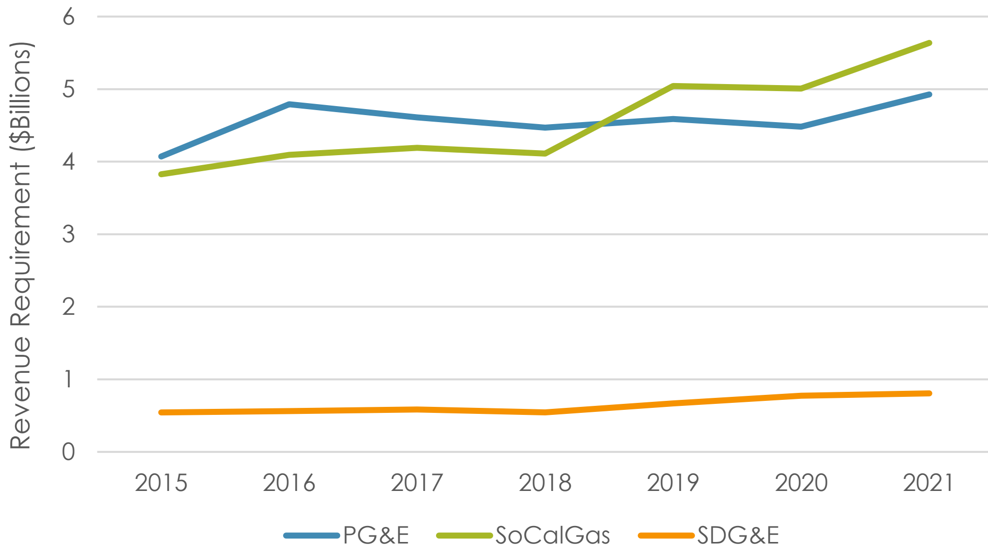
Gas utility transportation and distribution costs, a subset of total costs, increased by 5.0 percent from 2020 to 2021. Transportation costs for PG&E and SoCalGas increased by 7.1 percent and 4.6 percent, respectively, while SDG&E decreased by 4.6 percent.

Another subset of total costs is core procurement. In 2021, overall core procurement increased for each of the three gas IOUs compared to 2020, with an aggregate increase of 35.8 percent. Core procurement costs for PG&E, SoCalGas and SDG&E increased by 12.4 percent, 53.5 percent and 49.8 percent respectively.

A third component of total costs, natural gas PPP costs, increased by 9.5 percent from 2020 to 2021. PPP costs for PG&E increased by 52.5 percent while SoCalGas and SDG&E decreased by 10.8 percent and 3.9 percent, respectively. These are the expenditures for CARE and low-income energy-efficiency programs, both of which are designed to subsidize low-income households' utility bills.

Figure 7.2 show the trends in natural gas utility revenue requirements by utilities.

Figure 7.2: Historical Trends in Gas Utility Revenue Requirement ($ Billions)



Core Gas Procurement

The gas utilities recover the actual cost of procurement of natural gas for core customers through a rate component called the gas procurement rate. The gas procurement rate changes every month to reflect the most current commodity prices for natural gas.

Core gas customers in California have the option to choose between utility gas procurement service and gas procurement service from other entities called Core Transport Agents (CTAs). Even with CTAs, over 80 percent of core gas customers still receive gas procurement service from the utility. In contrast, almost all larger, noncore natural gas consumers (industrial customers or electric generators) procure their own natural gas supplies using non-utility suppliers. The procurement costs shown in this section reflect only the utilities' costs of providing procurement service to core customers.

Core procurement costs include the various costs associated with procuring natural gas supplies for a utility's core gas customers, such as the cost of the commodity, interstate pipeline capacity costs, hedging costs, and other costs. However, the major component of core procurement costs is the cost of the commodity itself.

Due to a significant decrease in the price of natural gas since mid-2008, the state's natural gas utilities' procurement costs have decreased by 40 percent from 2014 to 2020.

In 2020, procurement costs aggregated across the IOUs decreased by 18 percent (as discussed later). However, a polar vortex event, which occurred in the South and the

Midwest in February 2021 led to a rise in 2021 gas procurement costs. California saw gas prices spike as a result of the increased demand in states hit by the cold weather, a decreased production due to freeze-offs in Texas and Oklahoma basins, and the marketers' movement of gas to highest-priced markets.

In 2021, core procurement costs aggregated across the IOUs increased by 35.8 percent, with increases most pronounced for SoCalGas and SDG&E at 53.5 percent and 49.8 percent, respectively. This increase is due to a surge in natural gas commodity prices. Gas commodty prices have increased significantly this winter not only in California but nationally and globally. Gas production dropped during the initial part of the pandemic along with demand, but with the rapid economic recovery in 2021, gas demand returned to pre-pandemic levels very quickly, and gas production struggled to match the pace of increase in demand. The extremely high cost of natural gas globally has driven an increase in exports of liquified natural gas exports to Europe and Asia which are also experiencing constraints, further decreasing U.S. supplies and putting upward pressure on gas prices. Cold winter weather in the upper Midwest and Northeastern U.S. in January and into February has increased heating demand and put upward pressure on gas prices. In addition, there is reduced interstate pipeline capacity to California. Specifically, El Paso Natural Gas experienced an explosion and subsequent outage on its Line 2000 in Arizona in August 2021, which reduced westbound interstate pipeline flows to both SoCalGas and SDG&E, and is still ongoing as of March 2022.

Neither the CPUC nor FERC regulates the wholesale price of natural gas.

Table 7.4 and **Figure 7.3** show the historical revenue requirement for natural gas core procurement.

Table 7.4: Historical Core Procurement Revenue Requirement ($000)

	2015	2016	2017	2018	2019	2020	2021
PG&E	1,289,757	1,020,570	1,158,601	879,270	935,782	770,337	865,924
SoCalGas	951,033	912,847	1,154,731	1,048,393	1,134,044	923,497	1,417,147
SDG&E	131,006	120,352	151,850	139,506	157,016	128,346	192,212
Total	**2,371,796**	**2,053,769**	**2,465,182**	**2,067,169**	**2,226,842**	**1,822,180**	**2,475,283**

Figure 7.3: Historical Natural Gas Core Procurement Revenue Requirement ($ Billions)

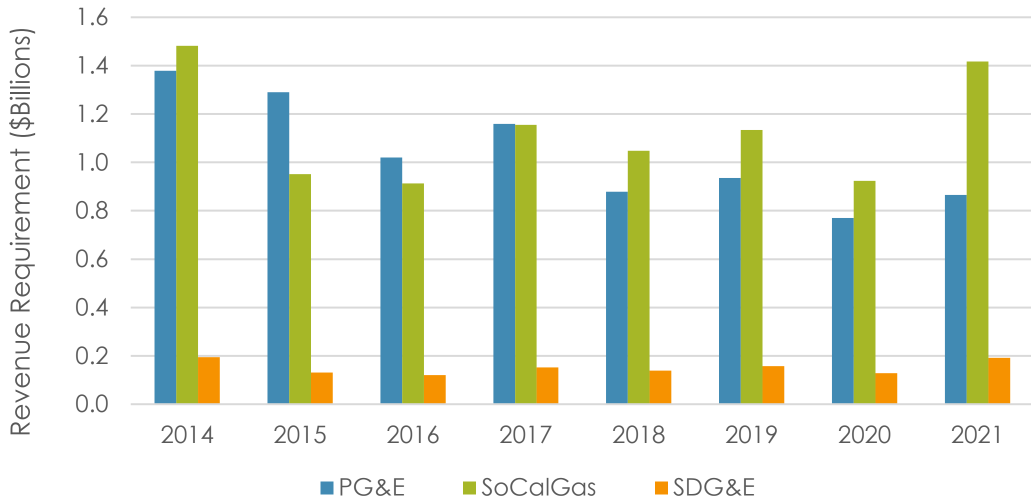


Table 7.5 shows the change in revenue requirement for core procurement.

Table 7.5: Percentage Change in Revenue Requirement for Core Procurement (2016-2021)

	2016-17	2017-18	2018-19	2019-20	2020-21
PG&E	13.5%	(24.1%)	6.4%	(17.7%)	12.4%
SoCalGas	26.5%	(9.2%)	8.2%	(18.6%)	53.5%
SDG&E	26.2%	(8.1%)	12.6%	(18.3%)	49.8%
Total	**20.0%**	**(16.1%)**	**7.7%**	**(18.2%)**	**35.8%**

For 2021 compared to 2020, **Table 7.5** shows an overall core procurement increased for each of the three IOUs, with an aggregate increase of 35.8 percent. For PG&E, core procurement increased by 12.4 percent. SoCalGas and SDG&E core procurement increased by 53.5 percent and 49.8 percent, respectively. The large increase in SoCalGas and SDG&E core procurement prices are due to increased commodity prices and supply disruptions due to a long term outage on the El Paso interstate pipeline to southern California.

In 2021, core gas procurement costs accounted for about 21.8 percent of the total utility costs.

For prior years, **Table 7.5** shows that for 2020 compared to 2019, overall core procurement decreased for each of the three IOUs, with an aggregate reduction of 18.17 percent. For PG&E, core procurement revenue requirement decreased by 18 percent due to reduced gas sales forecast volume and reduced commodity price. In March 2020, the Gas Cost Allocation Proceeding was implemented, which adopted an updated sales forecast used to calculate the illustrative Revenue Requirement for the

Core Gas Supply, a major component of PG&E's Core Gas Procurement. The sales forecast was 19 percent lower compared to the previous years. The last time the sales forecast was updated was 2010. The annual weighted average cost of gas used to determine the revenue requirement decreased by 5.5 percent.

In 2020, compared to 2019, for SoCalGas, core procurement decreased by 18 percent and for SDG&E, core procurement decreased by 19 percent. For SoCalGas, the unweighted commodity price decreased about 11 percent, and core consumption in 2020 decreased by about 4 percent, mainly due to COVID-19 and warmer weather in 2020. The pattern for SDG&E was similar.

For 2019 compared to 2018, overall core procurement increased for each of the three utilities. The 7.72 percent increase in 2019 was due to the cold winter and IOUs' spot market purchases. In 2019, core gas procurement costs accounted for about 22 percent of the total utility costs.

For 2018, overall core gas procurement costs decreased from 2017. This decrease was reflected in the large reduction in core procurement costs (24 percent) for PG&E in 2017-2018. Procurement costs decreased by smaller margins for SDG&E (8 percent) and SoCalGas (9 percent) due to ongoing constraints on the SoCalGas system.

For 2016-17, **Table 7.5** shows large increases in the overall natural gas core procurement costs for the three major utilities. Procurement costs increased by 14 percent for PG&E. The increase in procurement costs was much larger at 26 percent for both SoCalGas and SDG&E, likely in response to system issues with storage and pipeline capacity.

Gas Transmission, Distribution, and Storage Costs

The CPUC authorizes natural gas distribution utilities' revenue requirements for operating their extensive natural gas transmission, distribution, and storage systems 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.

Table 7.6 shows historical revenue requirement for transportation for 2015-2021. With the recent emphasis on safety and replacement of aging infrastructure, 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" category, have increased by 53 percent from 2015 to 2021. Such costs increased by 51 percent, 55 percent, and 55 percent for PG&E, SoCalGas, and SDG&E, respectively, from 2015 to 2020.

Table 7.6: Historical Transportation Revenue Requirement ($000)

	2015	2016	2017	2018	2019	2020	2021
PG&E	2,500,926	3,494,033	3,184,277	3,343,689	3,389,751	3,531,809	3,783,288
SoCalGas	2,511,953	2,850,105	2,693,301	2,741,585	3,550,769	3,723,109	3,896,051
SDG&E	378,037	409,148	397,819	373,133	478,127	614,121	806,478
Total	**5,390,916**	**6,753,286**	**6,275,397**	**6,458,407**	**7,418,647**	**7,869,039**	**8,264,942**

Table 7.7 shows the change in revenue requirement for transportation.

Table 7.7: Percentage Change in Revenue Requirement for Transportation (2016-2021)

	2016-17	2017-18	2018-19	2019-20	2020-21
PG&E	(8.9%)	5.0%	1.4%	4.2%	7.1%
SDG&E	(5.5%)	1.8%	29.5%	4.9%	4.6%
SoCalGas	(2.8%)	(6.2%)	28.1%	28.4%	(4.6%)
Total	**(7.1%)**	**2.9%**	**14.9%**	**6.1%**	**5.0%**

In **Table 7.7**, comparing 2021 to 2020, gas transportation costs increased by 5.0 percent and represented 72.7 percent of total utility gas costs. Transportation costs for PG&E and SoCalGas increased by 7.1 percent and 4.6 percent, respectively, while SDG&E decreased by 4.6 percent.

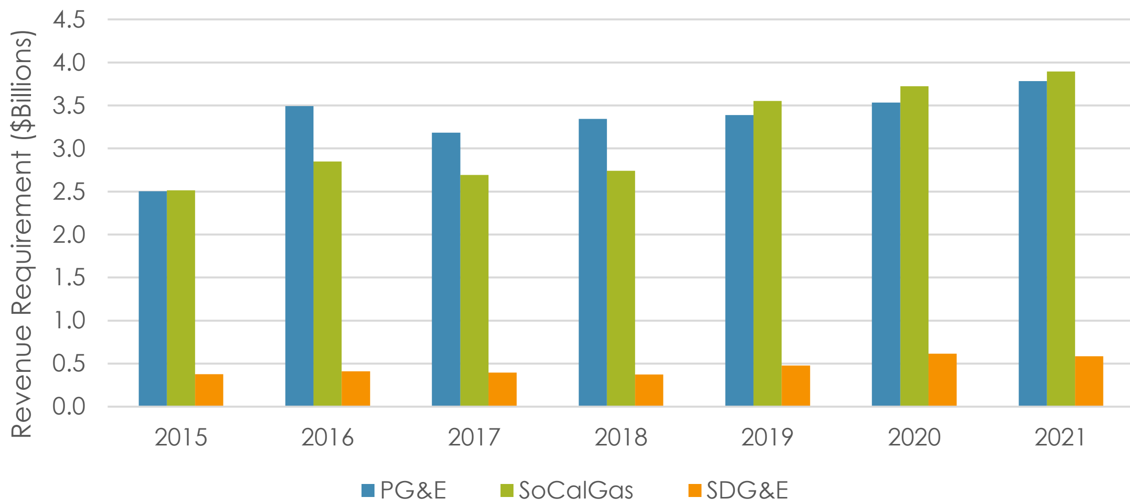
For 2021 compared to 2020, the increase in transportation costs for PG&E is due to increases in "Other Balancing Account Balances" for costs of Distribution Integrity Management Program (DIMP) and the GHG Program. The increase in transportation costs for SoCalGas is due to increases in Distribution, DIMP, and Transmission Integrity Management Program (TIMP) costs. The decrease in transportation costs for SDG&E is due to a decrease in DIMP costs.

For 2020 compared to 2019, the increase in aggregate Transportation revenue requirement of the three IOUs is predominantly accounted for by an increase in "Other Balancing Account Balances" ($328 million) and in Distribution and DIMP taken together ($208 million). These are offset by smaller decreases in several programs that are part of the Transportation revenue requirement.

A major factor in the increase in 2019 total transportation costs was that, for the first time for SoCalGas and SDG&E, GHG Program Costs and Proceeds (see further discussion below) were included in the transportation costs.

Figure 7.4 shows the historical revenue requirement for transmission, distribution, and storage.

Figure 7.4: Historical Natural Gas Transportation Revenue Requirement ($ Billions)



Legislative Program 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 (PPP) Costs, discussed in detail below. Information on the applicable State-Mandates (including PUC Sections) for covered programs is included in Appendix B for Gas Costs.

Table 7.8 shows the 2021 revenue requirement for State-Mandated natural gas programs.

Table 7.8: 2021 State Mandated Programs Revenue Requirement ($000)

	PG&E	SDG&E	SoCalGas	Total
Self Generation Incentive Program (SGIP)	12,990	1,545	16,272	**30,807**
California Solar Initiative (CSI)	13,138	816	5,979	**19,933**
CPUC Fee[83]	29,100	N/A	N/A	**29,100**
Franchise Fee Surcharge (G-SUR)[84]	9,643	3,352	18,229	**31,224**
Greenhouse Gas (GHG) Program	103,476	25,333	184,057	**312,866**
Energy Efficiency (EE) Programs	78,051	1,677	109,736	**189,464**
Low Income Energy Efficiency (LIFE)	22,922	0	0	**22,922**
Public Interest RD&D and State Board of Equalization (BOE) Administrative Fees	11,217	1,230	12,755	**25,202**
California Alternate Rates for Energy (CARE) Program	165,477	25,756	201,561	**392,794**
School Energy Efficiency Stimulus (SEES) Program	N/A	4,541	N/A	**4,541**
Total	**446,014**	**64,250**	**548,589**	**1,058,853**

Greenhouse Gas Compliance Costs and Allowance Proceeds

Since January 1, 2015, natural gas utilities have been covered under California's Greenhouse Gas Cap-and-Trade Program. As covered entities under the program, the natural gas utilities must buy compliance instruments (offsets and allowances) and surrender them to the California Air Resources Board (CARB) to account for GHG emissions associated with the combustion or oxidation of fuels they provide to customers in California (less any amount delivered to covered entities that supply their own compliance instruments to CARB). CARB holds quarterly allowance auctions where entities can buy and sell allowances. IOUs can also procure compliance instruments on secondary markets or through contractual arrangements.

CARB allocates some allowances to natural gas utilities on behalf of their ratepayers. The Cap-and-Trade Program requires the investor-owned natural gas utilities to sell an increasing share of these allowances at CARB's quarterly allowance auctions and use the proceeds for the benefit of ratepayers, starting at 25 percent of their allocated allowances in 2015 and increasing at a rate of 5 percent per year through 2030 (when 100 percent will be sold for ratepayer benefit). For 2021, natural gas utilities were required to sell 55 percent of allocated allowances for ratepayer benefit. The proceeds from the sale of GHG allowances must be used exclusively for ratepayer benefit, consistent with the goals of AB 32 (2006), CARB regulations, and as directed by the CPUC. The CPUC has determined the methodologies the utilities should use to return proceeds. D.15-10-032 and D.18-03-17 instructed natural gas utilities to return proceeds

[83] SDG&E and SoCalGas did not include the CPUC Fee in the revenue requirement reported here, but they do collect this fee as a separate charge on utility bills. The 2020 gas CPUC reimbursement fees for PG&E, SDG&E, and SoCalGas are $0.00577/therm.

[84] SDG&E did not include the G-SUR amount in the revenue requirement reported here, but SDG&E's 2020 G-SUR amount was $2.919 million, and shown as a CPUC Mandate, CPUC D.19-09-051.

to residential ratepayers each April as an on-bill credit, with each residential ratepayer receiving an equal share of their utilities' available proceeds. In addition to customer credits, pursuant to SB 1477 (2018), starting in fiscal year 2019, $50 million of allowance proceeds will be used for building decarbonization pilot projects each year through fiscal year 2023.[85]

Beginning in 2015, the natural gas utilities started tracking Cap-and-Trade Program related costs and allowance proceeds. However, these costs and credits were not introduced into customer rates until July 1, 2018.[86] PG&E provided the 2018 credit in October 2018 and the 2019 credit in April 2019. SDG&E and SoCalGas distributed their 2018 and 2019 credits together in April 2019. All investor-owned natural gas utilities now distribute the natural gas California Climate Credit annually in April.

In 2021, the natural gas utilities collectively introduced approximately $431 million in GHG costs into rates and returned approximately $287 million in allowance proceeds to customers (see **Table 7.9**).

Table 7.9: 2021 Greenhouse Gas Costs and Allowance Proceeds[87]

	2021 Natural Gas GHG Revenue Requirement	2021 Natural Gas Proceeds Distributed to Customers
PG&E	$221,151,764	($125,407,770)
SDG&E	$25,333,230	($20,006,613)
SoCalGas	$184,077,937	($141,550,374)
Total	**$430,562,931**	**($286,964,757)**

Gas Public Purpose Program (PPP) Costs

The CPUC also authorizes costs for three main categories of gas PPPs: energy efficiency (EE) and low-income EE, the CARE subsidy, and the gas public interest research and development program administered by the California Energy Commission. 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.

Costs authorized by the CPUC in 2021 for natural gas PPPs increased by 9.5 percent from 2020. Gas PPP costs made up 5.5 percent of total utility costs in 2021. PG&E

[85] Fiscal Year begins July 1. Funds for FY2019 were collected out of 2020 allowance proceeds, alongside FY2020 funding.

[86] D.18-03-017 instructed the natural gas utilities to net compliance costs against proceeds for the 2015-2017 period and either (1) amortize costs over a 12-month period starting in July 2018 if costs exceeded proceeds or (2) distribute the net proceeds in 2018 as a climate credit if proceeds exceeded costs. D.18-03-017 also ordered that 2018 GHG compliance costs be amortized in rates over an 18-month period starting July 2018.

[87] Revenue requirement and proceeds based on 2021 forecasted amounts. Proceeds excludes $49.2 million set aside for the Building Initiative for Low-Emissions Development program and Technology and Equipment for Clean Heating program.

aggregate PPP revenue requirement had an increase of 52.2 percent that is largely due to increases in PG&E's Energy Savings Assistance (ESA)[88] program and California Alternate Rates for Energy (CARE) program components. There is a decrease in SoCalGas and SDG&E PPP revenue requirement of 10.8 percent and 3.9 percent, respectively, primarily due to reduced funding for the ESA program.

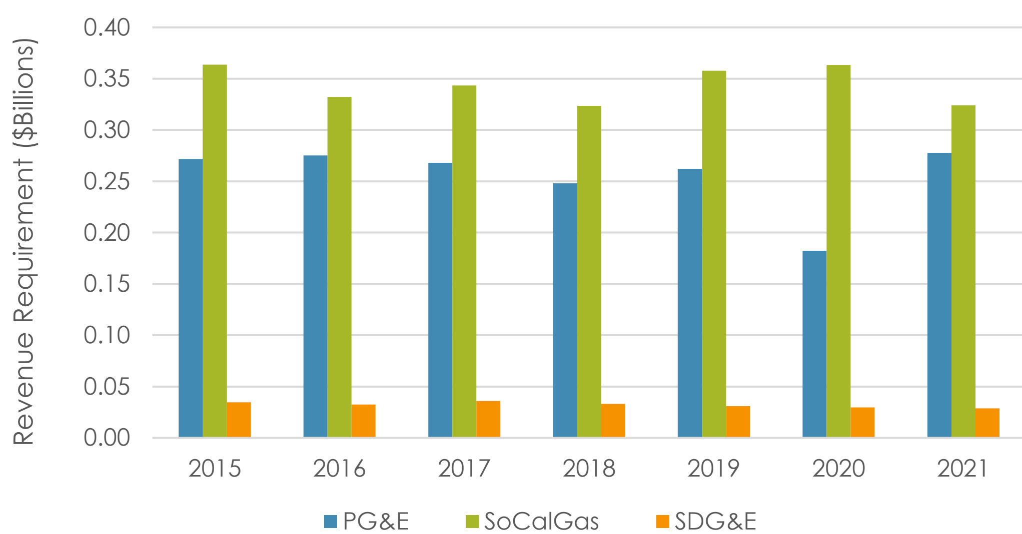
Gas PPP costs are recovered through the gas PPP surcharge on core and non-exempt noncore customers. Only non-CARE customers pay for the CARE subsidy portion of the gas PPP surcharge. The gas PPP surcharges are changed annually through advice letter filings, incorporating the revenue requirements for the gas PPPs adopted in CPUC proceedings.

Table 7.10 and **Figure 7.5** show the historical revenue requirement for public purpose programs.

Table 7.10: Historical Public Purpose Programs Revenue Requirement ($000)[89]

	2015	2016	2017	2018	2019	2020	2021
PG&E	271,726	275,079	267,938	248,026	262,036	182,489	277,667
SoCalGas	363,588	332,206	343,321	323,410	357,877	363,300	324,052
SDG&E	34,753	32,523	36,001	33,186	31,055	29,811	28,663
Total	**670,067**	**639,808**	**647,260**	**604,622**	**650,968**	**575,600**	**630,382**

Figure 7.5: Historical Revenue Requirement for Gas Utility Public Purpose Programs ($ Billions)



88 Formerly known as the Low-Income Energy Efficiency (LIEE) Program.

89 Costs authorized by the CPUC in 2020 for natural gas PPPs decreased by 11.6 percent from 2019. The decrease in aggregate PPP revenue requirement is largely due to a reduction in PG&E's Energy Savings Assistance (ESA) program component of PPP revenue requirement, and a true-up in 2020 for a large overcollection in 2019.

Appendices

A digital copy of the appendices can be found at:

https://www.cpuc.ca.gov/AB67Report

Appendix A: Historical Electric Revenue Requirements 2021-2018

2021 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,073,429**	**5,237,899**	**1,413,699**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	114,252	3,042,520	9,907
General Rate Case Revenues		CPUC Decisions	2,075,071	697,827	183,152
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,502,239	Included with Qualifying Facilities	659,328
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	380,681	1,481,544	643,541
Other		CPUC Decisions, Resolutions	1,185	16,009	(82,229)
Transmission Total			**2,035,538**	**1,253,026**	**736,175**
Reliability Services	FERC Order 459		10,316	(774)	(242)
Transmission Access Charge	FERC		57,898	258,290	(274,401)
Transmission Owner Rate Case Revenues	FERC		1,967,324	1,086,756	1,023,524
Other - FERC Rate Case Revenues	FERC		0	(91,246)	(21,410)
Other			0	0	8,704
Distribution Total			**5,595,486**	**6,587,686**	**1,599,694**
General Rate Case Revenues		CPUC Decisions	5,595,486	6,587,686	1,599,694
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**78,836**	**(43,059)**	**1,252**
Demand Side Management and Customer Programs Total*			**504,703**	**529,779**	**468,880**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	56,000	20,070
California Solar Initiative		CPUC Decisions	7,955	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	71,840	(1,706)	14,905
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	84,151	123,058	0
Energy Efficiency (non-PUC 399.8)			137,026	0	45,454
Electricity Program Investment Charge		CPUC Decisions	51,378	61,520	12,096
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	0	0	0
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	176,631	112,992	130,081
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	18,778	128,441	58,097
Other		CPUC Decisions, Resolutions	(102,908)	49,475	188,177
Other Regulatory Total*			**669,090**	**432,214**	**6,970**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	128,139	82,373	0
Hazardous Substance Mechanism		CPUC Decisions	35,480	0	80
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	100,348	100,183	0
Other		CPUC Decisions, Resolutions	405,123	249,658	6,890
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**0**	**0**	**0**
Wildfire Fund NBC	AB 1054	CPUC Decisions	**403,357**	**388,714**	**90,159**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**13,483**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**24,387**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**8,283**	**4,494**
Electric Total			**14,384,826**	**14,394,543**	**4,334,807**

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix A (cont.)

2020 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,514,686**	**5,514,150**	**1,507,396**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	183,050	3,124,621	6,701
General Rate Case Revenues		CPUC Decisions	2,238,948	735,315	183,153
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,851,969	Included with Qualifying Facilities	857,111
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,235,381	1,642,236	514,612
Other		CPUC Decisions, Resolutions	5,337	11,978	(54,182)
Transmission Total			**2,469,714**	**949,095**	**559,089**
Reliability Services	FERC Order 459		(36,546)	0	624
Transmission Access Charge	FERC		490,935	45,336	(287,001)
Transmission Owner Rate Case Revenues	FERC		2,015,324	962,976	858,000
Other - FERC Rate Case Revenues	FERC		0	(59,218)	(19,166)
Other			0	0	6,632
Distribution Total			**4,988,079**	**4,777,874**	**1,517,842**
General Rate Case Revenues		CPUC Decisions	4,988,079	4,777,874	1,517,842
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**89,909**	**(39,847)**	**1,048**
Demand Side Management and Customer Programs Total*			**161,861**	**286,496**	**462,716**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	56,637	20,070
California Solar Initiative		CPUC Decisions	7,955	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	74,097	21,483	14,736
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	98,941	46,541	0
Energy Efficiency (non-PUC 399.8)			(62,284)	0	71,388
Electricity Program Investment Charge		CPUC Decisions	97,834	76,900	16,280
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	71,412	65,808	13,145
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	91,616	(8,531)	124,112
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	18,300	(13,920)	52,512
Other		CPUC Decisions, Resolutions	(295,863)	41,578	150,473
Other Regulatory Total*			**439,683**	**98,209**	**8,064**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	301,787	51,626	0
Hazardous Substance Mechanism		CPUC Decisions	29,836	0	164
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	47,117	46,584	0
Other		CPUC Decisions, Resolutions	60,943	0	7,900
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(974)**	**(5,400)**	**(1,100)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**427,327**	**428,069**	**66,926**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**0**	**0**	**16,840**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**3,669**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**3,181**
Electric Total			**14,093,952**	**12,008,645**	**4,142,002**

*Recovered in distribution rate component

**Not reported elsewhere.

Appendix A (cont.)

2019 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,388,555**	**5,926,553**	**1,668,615**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	181,551	2,719,189	7,566
General Rate Case Revenues		CPUC Decisions	2,156,844	670,615	244,650
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,931,130	Included with Qualifying Facilities	746,366
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,041,266	2,494,399	735,655
Other		CPUC Decisions, Resolutions	77,763	42,350	(65,622)
Transmission Total			**2,206,039**	**1,016,889**	**634,909**
Reliability Services	FERC Order 459		(24,241)	2,977	115
Transmission Access Charge	FERC		500,276	45,336	(265,539)
Transmission Owner Rate Case Revenues	FERC		1,736,739	1,039,554	900,051
Other - FERC Rate Case Revenues	FERC		(6,735)	(70,978)	(7,255)
Other			0	0	7,537
Distribution Total			**5,004,292**	**3,881,203**	**1,296,667**
General Rate Case Revenues		CPUC Decisions	5,004,292	3,881,203	1,296,667
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**79,414**	**(27,773)**	**(590)**
Demand Side Management and Customer Programs Total*			**323,135**	**(38,479)**	**512,218**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,851	55,998	20,069
California Solar Initiative		CPUC Decisions	7,955	3,840	2,002
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	68,419	37,997	11,838
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	92,009	92,892	0
Energy Efficiency (non-PUC 399.8)			73,624	0	104,038
Electricity Program Investment Charge		CPUC Decisions	89,885	76,095	17,138
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	129,493	63,617	5,829
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	57,758	(1,288)	38,000
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	3,381	(10,615)	123,934
Other		CPUC Decisions, Resolutions	(259,241)	(357,015)	189,369
Other Regulatory Total*			**70,252**	**46,584**	**5,270**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	4,800	0	0
Hazardous Substance Mechanism		CPUC Decisions	39,657	0	270
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	48,009	46,584	0
Other		CPUC Decisions, Resolutions	(22,214)	0	5,000
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(4,057)**	**(5,437)**	**(434)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**376,681**	**366,979**	**77,388**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**(136,983)**	**0**	**12,493**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(46,396)**	**0**	**0**
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**705**	**5,165**
Electric Total			**13,260,932**	**11,167,224**	**4,211,701**

*Recovered in distribution rate component

**Not reported elsewhere.

Appendix A (cont.)

2018 Revenue Requirements ($000)

Rate Component	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,668,922**	**5,934,570**	**1,822,448**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	182,537	2,594,336	43,088
General Rate Case Revenues		CPUC Decisions	1,981,324	750,267	242,986
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,068,222	Included with Qualifying Facilities	691,131
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	1,398,617	2,352,938	887,777
Other		CPUC Decisions, Resolutions	38,223	237,030	(42,534)
Transmission Total			**2,146,305**	**1,024,468**	**502,821**
Reliability Services	FERC Order 459		170,611	4,136	734
Transmission Access Charge	FERC		430,524	(26,963)	(304,074)
Transmission Owner Rate Case Revenues	FERC		1,556,910	1,162,882	813,492
Other - FERC Rate Case Revenues	FERC		(11,740)	(115,588)	(13,302)
Other			0	0	5,970
Distribution Total			**4,702,384**	**4,663,722**	**1,299,314**
General Rate Case Revenues		CPUC Decisions	4,702,384	4,663,722	1,299,314
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**22,625**	**4,400**	**(939)**
Demand Side Management and Customer Programs Total*			**328,882**	**181,450**	**566,662**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	59,849	55,998	0
California Solar Initiative		CPUC Decisions	8,292	6,000	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	41,271	42,854	19,358
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,806	312,268	0
Energy Efficiency (non-PUC 399.8)			251,626	0	112,520
Electricity Program Investment Charge		CPUC Decisions	96,989	69,840	47,060
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	82,946	62,540	16,684
CARE Admin., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	38,391	(3,259)	(7,000)
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	0	0
Other PPP		CPUC Decisions, Resolutions	(26,720)	18,112	93,832
Other		CPUC Decisions, Resolutions	(344,568)	(382,903)	284,208
Other Regulatory Total*			74,607	0	1,318
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
Hazardous Substance Mechanism		CPUC Decisions	36,183	0	223
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	38,133	0	0
Other		CPUC Decisions, Resolutions	292	0	1,095
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	(1,171)	0	0
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	408,607	406,524	91,076
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	(79,700)	0	29,399
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	(3,773)	0	0
Franchise Fee Surcharge**	PUC Sections 6350-6354, 6231	CPUC Decisions	0	4,243	6,301
Electric Total			13,267,690	12,219,378	4,318,400

*Recovered in distribution rate component
**Not reported elsewhere.

Appendix B: Historical Natural Gas Revenue Requirements 2021-2018

2021 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**865,924**	**192,212**	**1,417,147**
Core Gas Supply Portfolio		CPUC Decisions	475,721	192,212	1,406,003
Other		CPUC Decisions	370,549	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	16,136	0	0
Incentive Mechanism		Report	3,518	0	11,144
Transportation Total			**3,783,288**	**585,603**	**3,896,051**
Distribution		CPUC Decisions	2,130,066	442,148	2,971,090
Gas Pipeline Integrity Mgmt. (DIMP)			1,323,885	53,177	272,922
PSEP			0	36,113	184,223
SoCalGas Only - SIMP			0	0	23,096
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	0	0	0
Gas Pipeline Integrity Mgmt. (TIMP)			0	17,064	105,021
PSEP			0	2,897	49,394
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	1,545	16,272
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	13,138	816	5,979
Annual Earning Assessment (AEAP)		CPUC Decisions	5,343	0	(315)
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	68,598
Haz Substance Mechanism (HSM)		CPUC Decisions	81,857	95	2,801
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, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	16,450
Core Pricing Flexibility Program		CPUC Decisions	0	0	333
Non-core competitive load growth program		CPUC Decisions	0	0	1,794
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	68,273	44,135	223,229
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	7,576	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	9,643	3,352	18,229
AB 32 Cap-And-Trade			(2,059)	2,058	9,591
GHG Program			103,476	25,333	184,057
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**277,667**	**28,663**	**324,052**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	78,051	1,677	109,736
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	22,922	0	0
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,217	1,230	12,755
Calif Alternate Rates for Energy (CARE) Program			165,477	25,756	201,561
School Energy Efficiency Stimulus (SEES) Program			0	4,541	0
GAS TOTAL			**4,926,879**	**806,478**	**5,637,250**

Appendix B (cont.)

2020 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**770,337**	**128,346**	**923,497**
Core Gas Supply Portfolio		CPUC Decisions	388,032	128,346	910,691
Other		CPUC Decisions	370,475	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	11,830	0	0
Incentive Mechanism		Report	0	0	12,806
Transportation Total			**3,531,809**	**614,121**	**3,723,109**
Distribution		CPUC Decisions	2,150,472	429,735	2,834,463
Gas Pipeline Integrity Mgmt. (DIMP)				16,208	56,726
PSEP				62,577	123,832
SoCalGas Only - SIMP					22,463
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,170,454	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				9,023	31,559
PSEP				7,766	34,743
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	2,060	16,271
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	8,477	1,401	22,759
Annual Earning Assessment (AEAP)		CPUC Decisions	2,937	0	304
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	38,678
Haz Substance Mechanism (HSM)		CPUC Decisions	68,836	204	2,647
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, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	15,793
Core Pricing Flexibility Program		CPUC Decisions	0	0	688
Non-core competitive load growth program		CPUC Decisions	0	0	1,913
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	16,138	47,992	241,218
CPUC Fee	PUC Section 431	Resolution M-4816	29,100	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,994	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	6,099	2,919	19,568
AB 32 Cap-And-Trade			24,294	2,286	9,696
GHG Program			35,018	31,950	249,788
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**182,489**	**29,811**	**363,300**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	70,279	812	93,255
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	(9,378)	11,572	134,474
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,172	3,053	11,338
Calif Alternate Rates for Energy (CARE) Program			111,416	14,374	124,233
GAS TOTAL			**4,484,635**	**772,278**	**5,009,906**

Appendix B (cont.)

2019 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**935,782**	**157,016**	**1,134,044**
Core Gas Supply Portfolio		CPUC Decisions	506,105	157,016	1,117,245
Other		CPUC Decisions	422,266	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	4,848	0	0
Incentive Mechanism		Report	2,563	0	16,799
Transportation Total			**3,389,751**	**478,127**	**3,550,769**
Distribution		CPUC Decisions	2,085,766	402,360	2,796,303
Gas Pipeline Integrity Mgmt. (DIMP)				7,785	49.021
PSEP				35,910	83,110
SoCalGas Only - SIMP					28,103
SoCalGas Only - Aliso Canyon					
Transmission		CPUC Decisions	1,178,640	0	0
Gas Pipeline Integrity Mgmt. (TIMP)				6,361	49,671
PSEP					27,391
Advanced Metering Infrastructure		Report	0	0	21,750
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	1,545	16,270
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	7,358	1,834	25,492
Annual Earning Assessment (AEAP)		CPUC Decisions	612	0	258
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	48,562
Haz Substance Mechanism (HSM)		CPUC Decisions	91,470	580	4,223
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, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	15,658
Core Pricing Flexibility Program		CPUC Decisions	0	0	1,619
Non-core competitive load growth program		CPUC Decisions	0	0	2,266
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	(76,948)	10,313	43,780
CPUC Fee	PUC Section 431	Resolution M-4816	11,661	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	6,849	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	7,047	2,521	20,492
AB 32 Cap-And-Trade			25,403	615	9,264
GHG Program			38,903	8,303	307,536
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**262,036**	**31,055**	**357,877**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	64,668	10,996	102,319
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	78,343	6,436	131,837
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,092	1,258	14,136
Calif Alternate Rates for Energy (CARE) Program			107,933	12,365	109,585
GAS TOTAL			**4,587,569**	**666,198**	**5,042,690**

Appendix B (cont.)

2018 Revenue Requirements ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**879,270**	**139,506**	**1,048,393**
Core Gas Supply Portfolio		CPUC Decisions	517,473	139,506	1,037,040
Other		CPUC Decisions	362,041	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	(3,316)	0	0
Incentive Mechanism		Report	3,072	0	11,353
Transportation Total			**3,343,689**	**373,133**	**2,741,585**
Distribution		CPUC Decisions	1,964,824	325,765	2,331,772
Transmission		CPUC Decisions	1,281,236	0	0
Advanced Metering Infrastructure		Report	0	0	31,780
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	12,990	2,317	24,405
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	6,722	1,638	13,862
Annual Earning Assessment (AEAP)		CPUC Decisions	182	0	638
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	52,872
Haz Substance Mechanism (HSM)		CPUC Decisions	83,469	520	1,396
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, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	12,924
Core Pricing Flexibility Program		CPUC Decisions	0	0	784
Non-core competitive load growth program		CPUC Decisions	0	0	1,795
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0	0	0
Z-Factor		CPUC Decisions	0	0	0
Other Balancing Accts Balances		Report	10,526	6,261	28,610
CPUC Fee	PUC Section 431	Resolution M-4816	7,837	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	5,102	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	5,842	2,057	22,589
AB 32 Cap-And-Trade			19,677	614	6,461
GHG Program	Sections 95851 (b), and 95852 (c) of Title 17	CPUC Decisions	(54,718)	-	-
Public Purpose Program Surcharges Total	**PUC Sections 399.8, 890-900**	**CPUC Decisions**	**248,026**	**33,186**	**323,410**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	57,823	11,931	74,527
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	75,742	16,002	129,252
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,840	1,203	13,294
Calif Alternate Rates for Energy (CARE) Program			103,621	4,050	106,337
GAS TOTAL			**4,470,985**	**545,825**	**4,113,388**