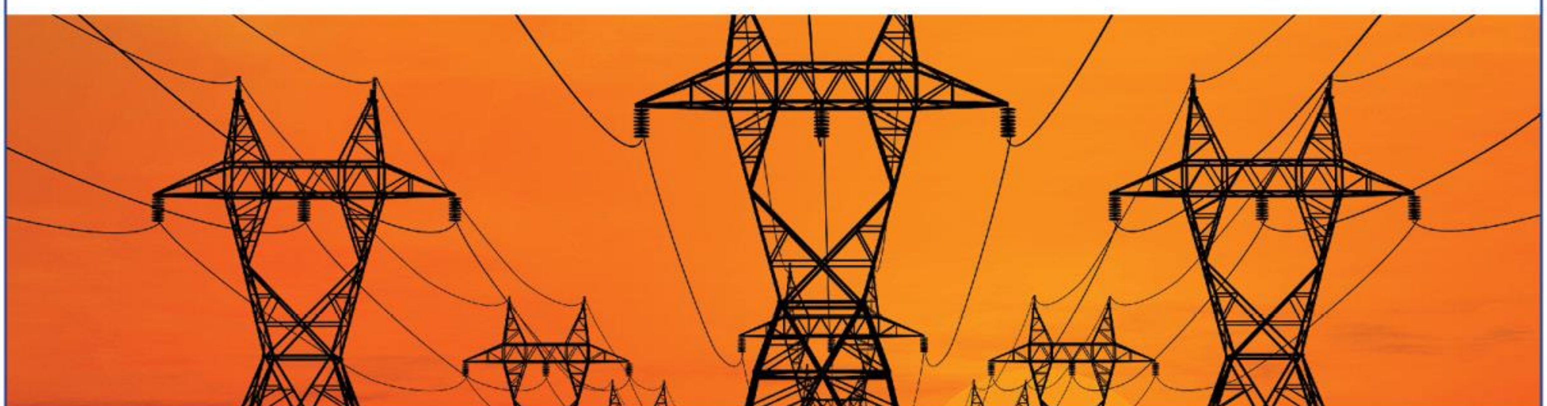
California Public Utilities Commission

Electric and Gas Utility Cost Report

Public Utilities Code Section 913 Report to the Governor and Legislature



April 2016

I. INTRODUCTION

Enacted as Assembly Bill (AB) 67 in 2005, Public Utilities Code 913 requires the California Public Utilities Commission (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 also 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 report is submitted by the CPUC to fulfill these statutory requirements.

Background

The State of California has been a national leader in energy policy, setting innovative mandates for renewable energy, demand side management, and greenhouse gas emissions regulation. With the implementation of these policies, the utilities' cost structures and the rate setting process have become increasingly complex. The funds that each utility is authorized to collect in rates to meet its expenses — commonly referred to as revenue requirements — are approved through several different regulatory proceedings corresponding to various mandates.

The California Legislature passed AB 67 in 2005 to establish an annual reporting requirement that would identify the costs to ratepayers of all utility programs and activities. 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 2005.

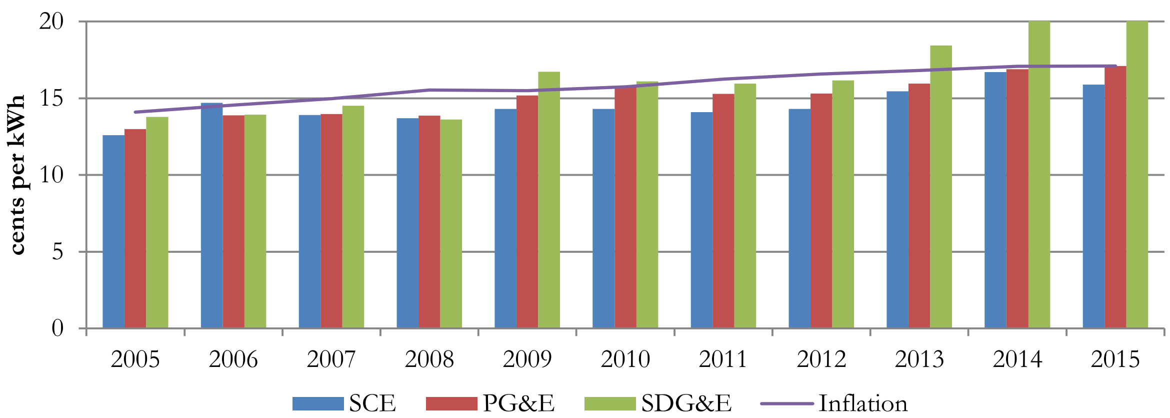
The report presents an analysis of the CPUC-authorized revenue requirements for the four major California investor-owned utilities (IOUs or utilities): Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas). Using sales forecasts, rates are set to collect these authorized revenue requirements. Any 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 ensures that the utilities only collect their authorized revenue requirements and that they recover their costs despite the effect of conservation programs on sales.

Overview

Electric Utility Costs

- **System average rate increases have generally tracked inflation until 2012.** Through 2015, system average rates across the three IOUs has increased at an annual average of approximately 3.4%, which is slightly above the average annual inflation rate of 2.0% over the same time period. Figure 1.1 shows the trend in average electric rates for the electric IOUs. In 2015, SCE's system average rate was 15.9¢/kWh, PG&E's was 17.1¢/kWh, and SDG&E's was 21.8¢/kWh.[1] The system average rate for SDG&E has increased recently due to a unique combination of factors, including an unusual increase in SDG&E's costs of procuring power as well as a delay in its 2012 General Rate Case which resulted in cost increases being compressed over a shorter period of time. To the extent that system average rates per utility continue to rise, the Commission should consider long term strategies for containing costs.

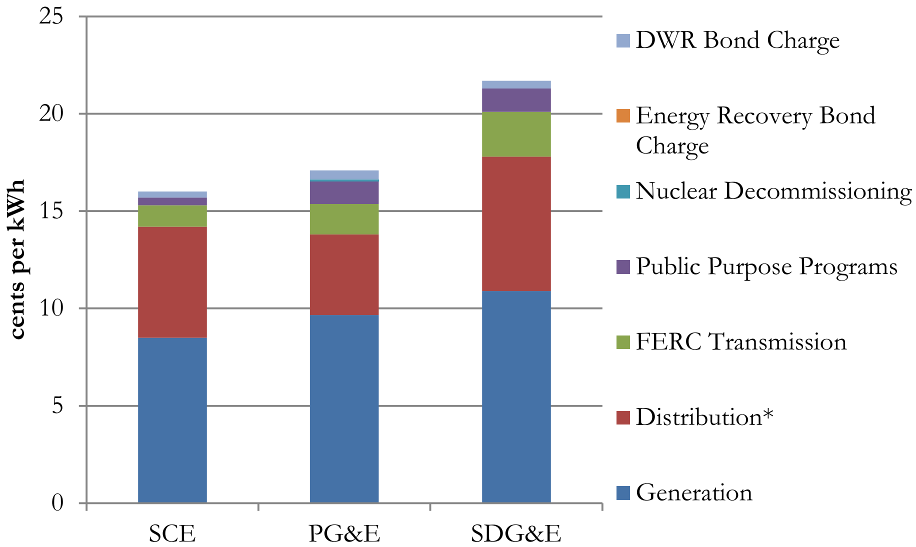
Figure 1.1: Trends in Average Rates



- **Electric generation and energy procurement are a large component of electric rates.** As shown in Figure 1.2, generation, provided through utility-owned generation and purchased power sources, collectively accounts for approximately 48% of the utilities' electric rates**.**

[1] SCE Advice Letter 3311-E (effective 11/24/15); PG&E Advice Letter 4689-E (effective 9/1/15); SDG&E Advice Letter 2791-E (effective 11/1/15).

Figure 1.2: 2015 Rate Components



*Distribution here includes some charges not related to distribution, but recovered through the Delivery Component of rates from all customers, both bundled and unbundled. These charges total 0.4¢ for SCE, -0.8¢ for PG&E and 0¢ for SDG&E.

- **Demand side management remains a cost effective method to meet new demand.** Energy efficiency programs provided bill savings over the 2013-2015 program cycle with demonstrated cost effectiveness.[2] Based upon evaluated lifecycle total costs and benefits during this time period, energy efficiency gas and electric savings exceeded costs by $646 million (see Figure 4.2). In addition to energy efficiency, the CPUC has several legislatively mandated distributed generation and integrated demand side management programs, including the California Solar Initiative (CSI) program, the Self-Generation Incentive Program (SGIP), and commercial and residential demand response programs such as A/C cycling.

- **Renewable Portfolio Standard (RPS) eligible energy remains a small but growing component of the revenue requirements.**[3] The IOUs collectively served 26% of their retail electricity load with renewable power in 2014. Additionally, the IOUs forecast that 28.8% of their 2015 retail electricity load will be met by renewable power.[4] In 2015, renewable power procurement made up 33.8% of the IOUs' generation revenue requirement and 16.1% of the total revenue requirement. Since 2003, more than 13,040 MW of new renewable capacity has achieved commercial operation under the RPS program.[5] The CPUC approved 15 contracts,

[2] Results are for 2013-2014 as well as the first two quarters of 2015 (10 quarters of program activity). Results for the full three-year portfolio will be presented in next year's report.

[3] Please refer to the Renewable Energy Procurement section on page 23 for a list of eligible renewable energy resources.

[4] Figures for actual load served by renewable power in 2015 will not be finalized until August 2016.

[5] RPS procurement figures for 2014 are sourced from the Annual 33% RPS Compliance Report submitted on September 4, 2015.

representing 2,069 MW of renewable capacity in 2015. More than 2,098 MW of renewable capacity came online in 2015.[6]

Gas Utility Costs

- **Total natural gas utility costs in 2015 increased by 0.2% from 2014.**
- **Natural gas utility revenue requirements for transmission, distribution and storage services increased by 12.6% in 2015 from 2014, and by 45% from 2010, as gas utilities place greater emphasis on safety and replacing aging infrastructure.**
- **Costs authorized by the CPUC for natural gas public purpose programs increased by 15.1% from 2014**, due to cost increases for low-income programs.

The remainder of this report provides a breakdown of the various electric and gas revenue requirement components and identifies the sources of the greatest increases in costs. Chapters II - V address electric revenue requirements and Chapter VI addresses gas revenue requirements. In addition to the detailed summary tables provided throughout the text, Appendix A provides summaries of the IOU revenue requirements organized by the rate components typically shown on customer bills. Finally, the revenue requirements identified in Appendix A include balancing account adjustments – however, the body of this report discusses Commission authorized revenue requirements without these adjustments.

Determining Revenue Requirements

Due to the increasingly varied nature of utility costs and the multitude of energy policy programs, the determination of revenue requirements and the ratesetting process at the CPUC have grown more complex over time. The following forums are used to determine the revenue requirements that the utilities are authorized to collect through rates:

1. **General Rate Cases (GRCs):** GRCs occur on a three year cycle at the CPUC and evaluate the regulated operations of the IOUs as well as determine the reasonableness of their requests for increases in revenue requirement.
2. **Transmission rate cases at the Federal Energy Regulatory Commission (FERC):** The CPUC is required to allow recovery of all FERC authorized costs.
3. **Energy Resource Recovery Account (ERRA) proceedings**: The CPUC reviews each utility's fuel and power purchase forecast and, to the extent deemed reasonable, passes through the revenue requirements without any profit or mark-up for the utility. Public purpose charges are also authorized here.
4. **Program Budget allocations**: Specific program area proceedings in which program budgets are determined.

[6] RPS capacity figures sourced from IOU self-reported information submitted to the RPS contract database on January 15, 2016.

The utilities earn a rate of return, or profit only, on costs that are utility-owned and capitalized (e.g. 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 or bundled service from the utility, and may generate their own power on site or buy power from a non-utility source (e.g., an Electric Service Provider (ESP), or a Community Choice Aggregator (CCA)).

These customers do not typically pay generation costs and instead pay only transmission and distribution costs; however, in some cases, these customers are 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 1.3 offers a breakdown of the major components of the electric IOUs' 2014 revenue requirements.

Table 1.3: 2015 Electric IOU Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Generation/Energy Procurement			
Purchased Power	$4,514,153	$4,412,244	$1,008,008
Utility Owned Generation	$2,185,558	$1,513,067	$399,351
Distribution	$4,399,854	$4,350,777	$1,138,103
Transmission	$1,610,878	$910,155	$423,318
Demand Side Management and Public Purpose Programs	$646,788	$545,126	$162,987
Bonds & Fees	$673,170	$485,956	$131,756
Total 2015 Revenue Requirement*	**$13,730,664**	**$12,198,048**	**$3,578,637**

* The numbers in the table do not add up to the Total 2015 Revenue Requirement for each utility due to other costs that do not fall under the categories provided here.

Ratebase

The ratebase is the book value, after depreciation, of the generation, distribution and transmission infrastructure owned and operated by the utility. Utilities earn a regulated rate of return (ROR) on ratebase. Other things being equal, a larger ratebase results in higher net income for the utilities.

Depreciation causes the utilities' ratebase for existing assets to decline over time, while building new plants or making capital improvements to existing plants causes their ratebase to increase. Changes in ratebase also result in changes in the depreciation allowance utilities are authorized to collect. As shown in Figure 1.5 below, the result of these competing effects has historically been a net increase in ratebase. Figure 1.5 indicates that between 2005 and 2015, the utilities' ratebase doubled in size from $24 billion to $52 billion, triggering corresponding increases in GRC revenue requirements.

Figure 1.4: 2015 Ratebase

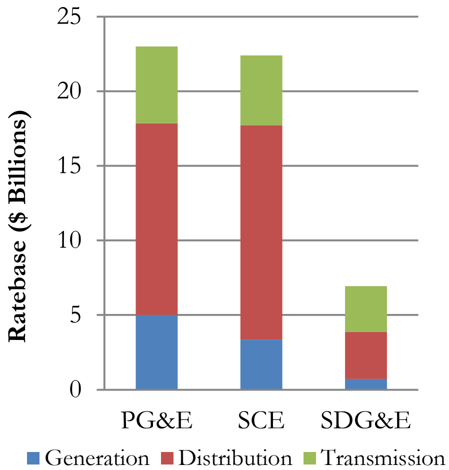
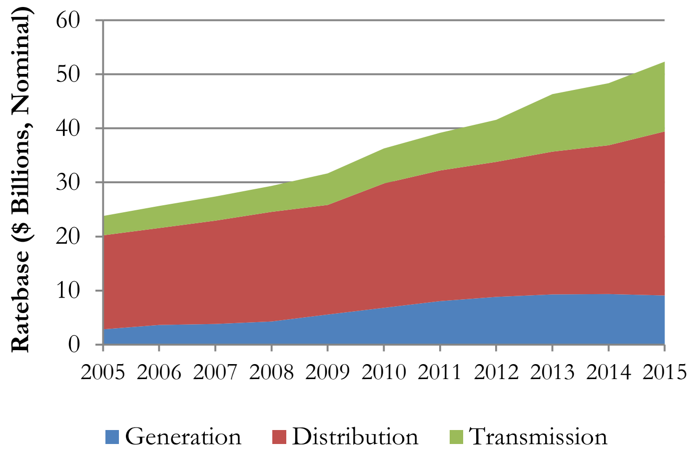


Figure 1.5: Trends in Ratebase



II. GENERAL RATE CASE REVENUE REQUIREMENTS

Costs that utilities can forecast with reasonable accuracy are examined and approved by the CPUC in GRC proceedings. These proceedings are usually on a three-year cycle for the major utilities, although this interval may be longer depending on the timing of the utility request or the scheduling needs of the CPUC. 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. 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.

Approximately 55% of the utilities' electric revenue requirements are set in GRCs at the CPUC and FERC, while the remaining 45% consists of pass-through of the costs of power procurement, DWR power charges, nuclear decommissioning trusts, Public Purpose Programs, fees, and regulatory expenses approved by the CPUC. The transmission revenue requirement determined by FERC in transmission owner rate cases follows similar test year ratemaking treatment.

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: Operations and Maintenance (O&M), Depreciation, Return on Ratebase and Taxes. Table 2.1 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.

Table 2.1: 2015 General Rate Case Revenue Requirements ($000)[7]

	PG&E	SCE	SDG&E
Operations and Maintenance	$2,392,236	$1,934,010	$687,343
Depreciation	$1,739,029	$1,506,374	$250,012
Return on Ratebase	$1,355,627	$1,389,954	$258,283
Taxes	$774,355	$804,710	$217,246
Total	**$6,261,246**	**$5,635,047**	**$1,412,884**

(Excludes FERC determined transmission revenue requirements)

- **Operations and Maintenance (O&M):** 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. In November 2014, the CPUC adopted a framework for incorporating risk-based decision making into GRCs that will take place by means of two new procedures: the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, and a subsequent Risk Assessment Mitigation Phase (RAMP).

[7] 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.

Each utility's RAMP proceeding will utilize the reporting format developed in its S-MAP proceeding, and will describe how it plans to assess and mitigate its risks. The first S-MAPs were filed in 2015.[8] In the GRC proceedings, the CPUC undertakes a thorough review of O&M costs, separately, for generation and distribution related facilities, and for general plant.

- **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 Ratebase (ROR):** Because the utilities provide the upfront financing for all capitalized expenditures, the CPUC authorizes a ROR on the invested capital. The ROR is the weighted average cost of debt and shareholder equity, and the CPUC allows 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. 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.

In addition to the authorized ROR, the CPUC has instituted incentive programs, such as the Efficiency Savings and Performance Incentive mechanism, whereby utility shareholders are eligible to receive payments for achieving good energy savings performance. 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 ERRA proceedings.

Distribution Revenue Requirement

Since 2005, the total distribution revenue requirement, excluding franchise fees and taxes, has increased from $5.3 billion to $8.2 billion. Over the same time period, depreciation expenses have experienced the greatest increase, with a 7.0% average annual growth rate. O&M and ROR on ratebase have increased annually by 2.8% and 4.3%, respectively. The increases in distribution costs are primarily due to capital additions and infrastructure improvements to the distribution system, which have increased ratebase, as discussed on page 9.

[8] The three IOUs have filed their first S-MAP applications, and the proceeding is consolidated under A.15-05-002. The RAMP proceedings have not begun, but the first filing will be by SDG&E (expected in late 2016).

Figure 2.2: Trends in Distribution Revenue Requirement

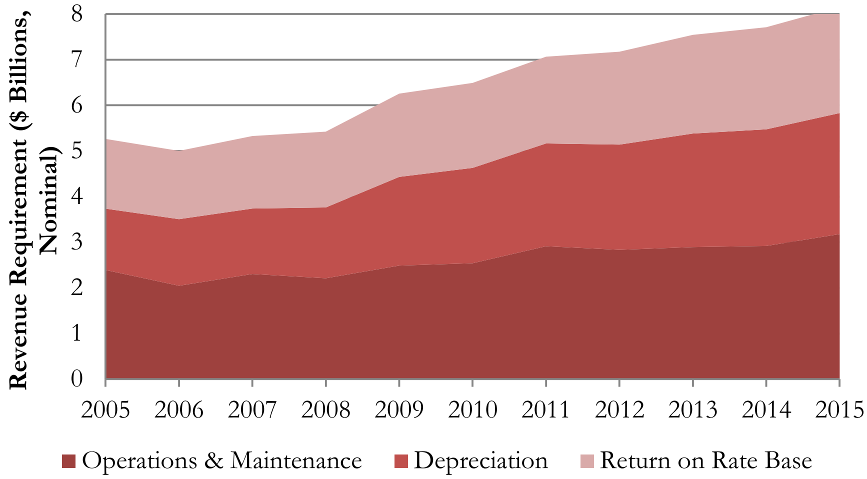


Table 2.3: 2015 Distribution Revenue Requirement ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,371,848	$1,266,744	$540,690
Depreciation	$1,278,772	$1,146,776	$226,341
Return on Ratebase	$974,879	$1,132,546	$217,247
Total	**$3,625,499**	**$3,546,067**	**$984,278**

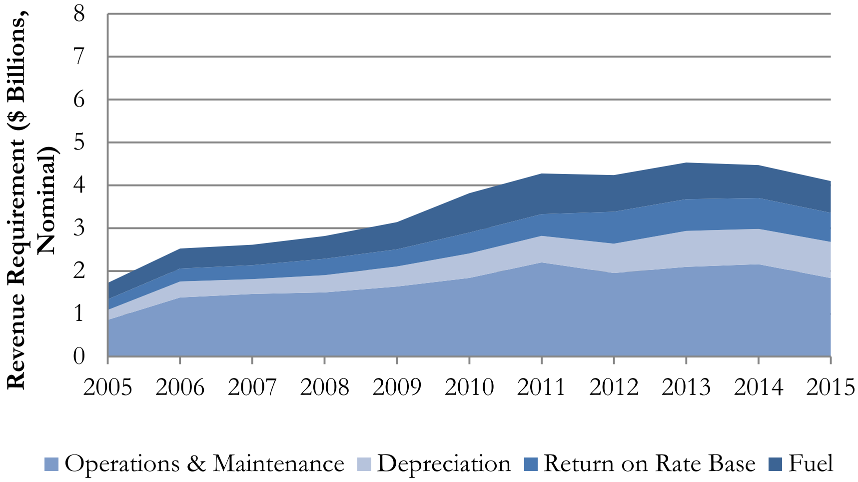
Utility Owned Generation Revenue Requirements

The revenue requirement for UOG includes O&M costs, depreciation and return on ratebase 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 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. As a result, the generation ratebase tends to increase over time as shown in Figure 2.4.

The recent spikes in UOG revenue requirement in 2011 and 2013 are mainly the result of amortization of large under-collections recorded in the utilities' balancing accounts. These accounts compare authorized generation revenue requirements to actual revenues collected through rates. Any amounts collected above or below authorized revenues are returned to, or collected from, ratepayers. The UOG revenue requirement decreased in 2015 because costs related to the San Onofre Nuclear Generation Station owned by SCE and SDG&E have been categorized as regulatory costs.

Following electric industry restructuring in the late 1990s and the utilities' divestiture of fossil-fueled generation, UOG (including fuel costs) now accounts for approximately 29.2% of the combined utility supply portfolio and approximately 13.9% of their combined revenue requirements.

Figure 2.4: Trends in Generation Revenue Requirement



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

Table 2.5: 2015 Generation Revenue Requirements ($000)

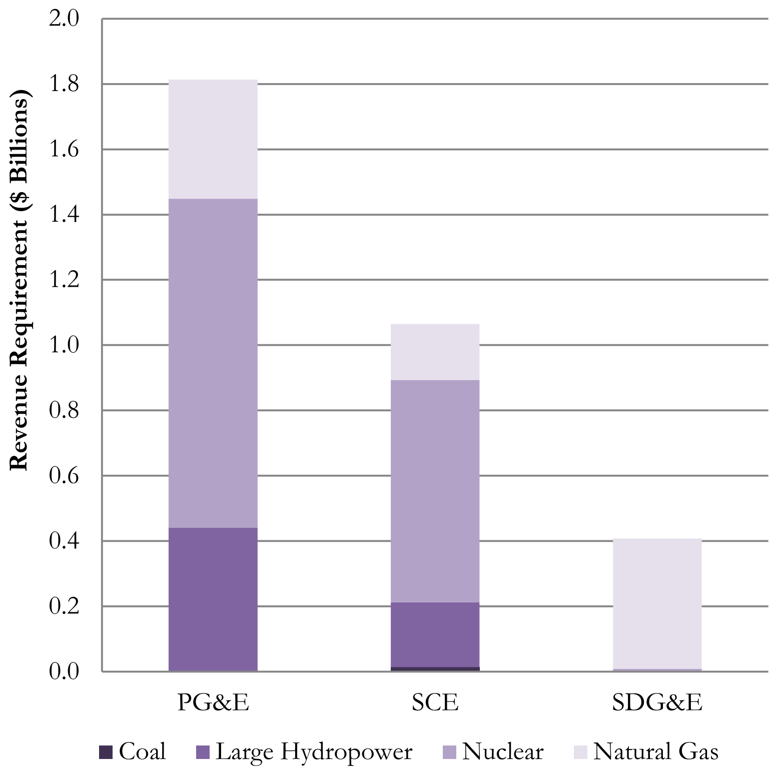
	PG&E	SCE	SDG&E
Operations and Maintenance	$1,020,388	$667,265	$146,653
Depreciation	$460,256	$359,598	$23,671
Return on Ratebase	$380,748	$257,407	$41,036
Total	$1,861,393	$1,284,270	$211,360

PG&E's UOG consists primarily of hydro-electric, nuclear power (Diablo Canyon) and a number of natural gas plants (e.g., the 660 MW Colusa Generation Station, 580MW 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. SCE no longer relies on coal since the Mohave Generating Station was taken out of service and SCE sold its share of the Four Corners plant.[9] 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.[10]

[9] The CPUC approved SCE's sale of its stake in the Four Corners plant in March 2012, and the sale was closed in December 2013.

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

Figure 2.6: 2015 Revenue Requirements of UOG Sources



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 in Arizona.[11] 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 decided in a 2014 decision in the SONGS Investigation (OII).

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:[12]

- **Fees for disposal and storage of spent nuclear fuel** are required by the US Department of Energy for temporary and permanent storage facilities.
- **Nuclear decommissioning** of generating plants at the end of their operating lives.

[11] 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.

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

Authorized Rate of Return

Figure 2.7: Trends in Weighted Average Rate of Return (ROR)

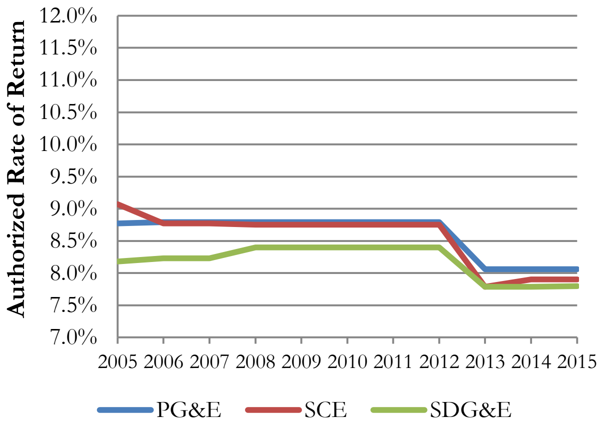


Figure 2.8: Trends Return on Equity (ROE)

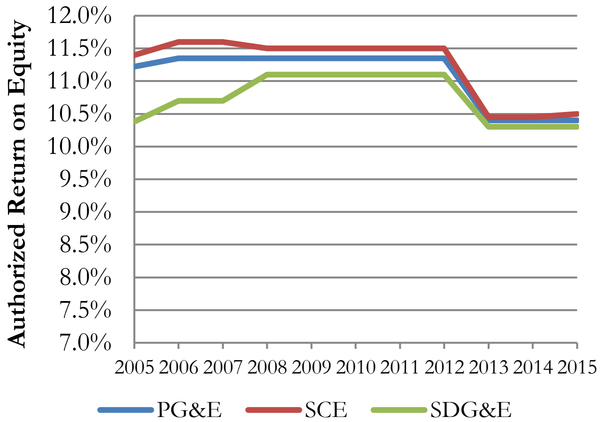


Figure 2.7 illustrates rate of return (ROR) authorized by the CPUC since 2006 for major energy utilities. ROR is the weighted average cost of debt, preferred and common stocks. The figure does not include ROR authorized by FERC for IOU transmission systems; it only includes ROR authorized by the CPUC for UOG and distribution. Figure 2.8 shows trends in the Return on Equity (ROE) component of ROR authorized by the CPUC since 2006. ROE is the utility's net income (less its preferred dividend requirement) over its shareholders' average common equity.

The utilities are currently required to file a complete cost of capital application every three years. SCE, SDG&E and PG&E filed their most recent cost of capital applications for test year 2013.

The utilities were expected to file test year 2016 cost of capital applications on April 20, 2015; however, the utilities requested and were granted waivers from filing. Instead, the utilities will file test year 2018 cost of capital applications in April 2017. The utilities ROR and ROE did not change in 2015 and will not change in 2016 based on the cost of capital.

Transmission Revenue Requirement

Background and Jurisdictional Separation History

As part of energy restructuring, the California Independent System Operator (CAISO) was created and given operational control[13] over the utilities' high voltage transmission lines on January 1, 1998, and authority for determining transmission revenue requirements was transferred to FERC[14]. The

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13 The Restructuring Decision (1996) functionally created the implementation of the CAISO through the acceptance of AB1890 (Sept. 24, 1996).

14 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).

transmission revenue requirements authorized by FERC include the same core components (O&M, depreciation, and return on rate base) as the general rate cases at the CPUC. However, typically transmission revenue requirements at FERC are determined through settlements and adopted as "black box" numbers without a breakdown of specific components. Therefore, the Commission does not have the same level of information for transmission costs that it does for generation and distribution costs. The CPUC is the constitutionally designated agency to represent the interests of California ratepayers in utility Transmission Owner (TO) rate cases at FERC proceedings, where utilities request changes in their transmission revenue requirements.

Each utility defines its high voltage transmission lines differently. PG&E, SDG&E and SCE respectively define all power lines at and above 60kV, 69kV and 200kV as transmission-level assets that are regulated by the FERC. All other electric power lines and assets remain under CPUC regulatory control and jurisdiction.

Transmission Revenue Requirements and Trends

The fundamental basis of the CPUC's advocacy role in FERC proceedings is one of containing ratepayer costs in the Transmission Owner (TO) rate case decision-making process.[15] To this end, the CPUC actively participates in TO rate cases before FERC to advocate for just and reasonable rates in wholesale electric market proceedings. Due to the importance and complexity of these rate cases, CPUC Legal and Energy Division staff examine a multitude of cost of service and capitalization issues for adequacy, cost effectiveness, safety, and prudence.

FERC determines the appropriate amount of transmission revenue requirement for the Investor Owned Utilities (IOUs). When the IOUs file their transmission revenue requirement requests, the CPUC team, other joint interveners and FERC staff review, analyze and critique the filings while also conducting discovery on the utilities filings to collect evidence and develop a fact-based recommendation on *fair and reasonable* revenue requirement to protect ratepayers. Generally, a FERC Administrative Law Judge facilitates a settlement, unless an impasse in the settlement process necessitates litigation.

In 2015, CPUC's representation in electric FERC-related work consisted of TO rate cases for the electric IOUs. In the aggregate, FERC ordered a reduction totaling $168.4 million[16] to the cost recovery requests filed by the IOUs in these rate cases. These savings are reflected in lower rate increases of electricity charges for ratepayers. **CPUC representation in FERC rate cases from 2005-2015 has resulted in a cumulative savings of over $1.332 billion for ratepayers.**

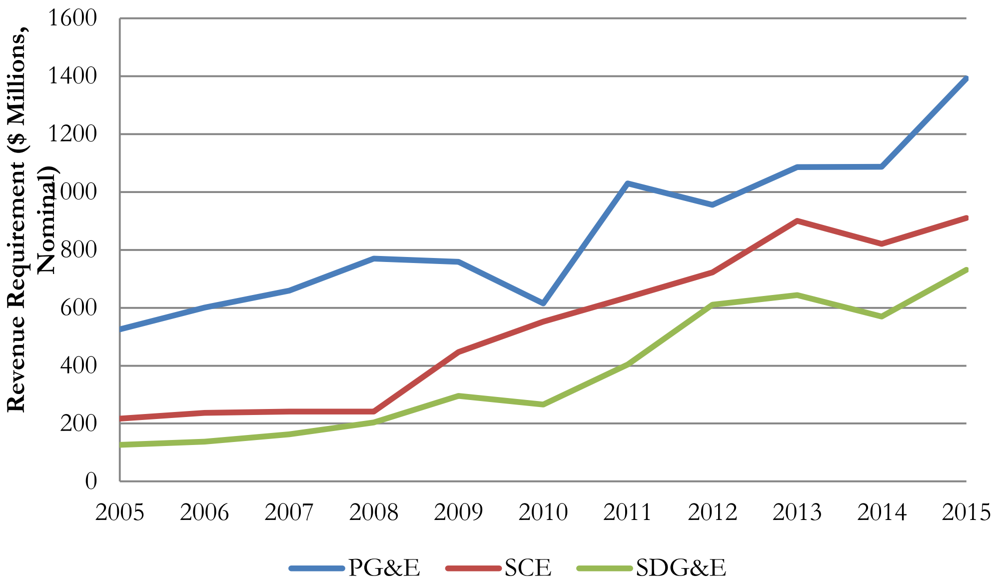
Transmission revenue requirements for the electric IOUs have been trending up since 2003. Historically, much of the increase in the revenue requirements is due to additional transmission plant capital additions which have been built by the utilities. More recently, the increases are a result of replacing and modernizing aging infrastructure, interconnecting new electric generation, and compliance with updated North American Electric Reliability Corporation (NERC) requirements. From 2005-2015, PG&E's filed transmission revenue requirement has increased at a 8.27% annual

[15] The CPUC has a statutory duty to represent the interests of California electric and gas consumers before the FERC (CPUC Code, Section 307(b)).

[16] Revenue requirement reductions for the PG&E TO16 case were $165.7 million (August, 2015); Mid-America Central California Transco case were $0.36 million (May, 2015); and Duke American Transmission Company (DATC) case were $2.3 million (April, 2015).

average rate; SCE's at a 9.54% annual average rate; and SDG&E's at a 16.52% annual average rate. These increases are driven primarily by CAISO reliability and RPS mandates.

Figure 2.9: Trends in Transmission Revenue Requirements[17]



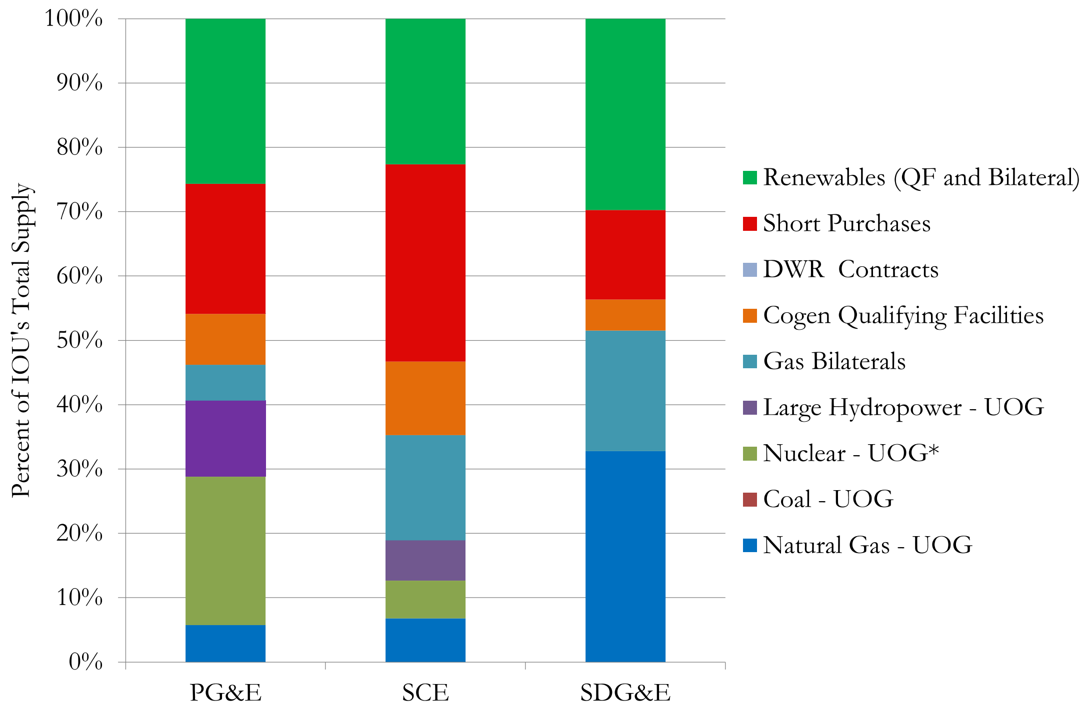
[17] Does not include costs related to Reliability Services or Transmission Access Charge.

III. POWER PROCUREMENT COSTS

The generation revenue requirement includes UOG costs (as discussed in Chapter II), 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 initially relied on purchased power for incremental electricity needs. This changed, however, with the expiration of power contracts and the acquisition of some new utility-owned natural gas plants.

In 2015, on a forecast basis, purchased power accounted for 71% of the total generation revenue requirement, while UOG comprised about 29%. Power purchase costs represent the largest component of generation costs and accounted for 34% of total revenue requirements. Recovery of these pass-through costs is authorized through ERRA proceedings and there is no mark-up or profit for the utilities on purchased power expenses.

Figure 3.1: 2015 Forecast Energy Supply for Electric Utilities



*SCE holds partial ownership in the Palo Verde Nuclear Generating Station in Arizona

Background

Heavy reliance on power purchases rather than utility owned power plants 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 generation market, the utilities were encouraged to divest at least 50% of their fossil-fueled generation. The CPUC provided a 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 June 1996 levels) 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 Department of Water Resources (DWR) to enter into power purchase contracts to stabilize the 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 integrating renewable resources into long term planning. The contracts resulting from these solicitations are reviewed by Procurement Review Groups 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% 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 Renewable Portfolio Standard (RPS) and required the utilities to procure 20% of their electricity demand from renewable resources by 2010. The statute also required each IOU to hold an annual solicitation to procure renewable power. SB 2 (2011) raised the RPS obligation to 33% by 2020. SB 350 (2014) again raised the RPS obligation to 50% by 2030.

Following the energy crisis, the CAISO redesigned its market structure and rules. The redesigned system, the Market Redesign and Technology Upgrade (MRTU), went operational in the spring of 2009. With MRTU, the market price is determined using many (approximately 3,000) dispersed locations or nodes instead of the earlier zonal pricing system. These changes were aimed at making the electricity market more efficient by accurately and transparently pricing generation and by prioritizing and optimizing generation siting and/or transmission upgrades.

Types of Purchased Power

DWR Contracts

DWR contracts were long term contracts that the Department of Water Resources entered into on behalf of IOU customers during the energy crisis. Each year, DWR submits its revenue requirement to the CPUC for adoption and subsequent collection from ratepayers through the DWR Power Charge. The total energy provided by DWR has been declining since 2003 as contracts expire. Due to the expiration and/or novation of these contracts, DWR's revenue requirement for all three utilities was negative in 2015 and resulted in a refund of operating reserves to PG&E, SCE and

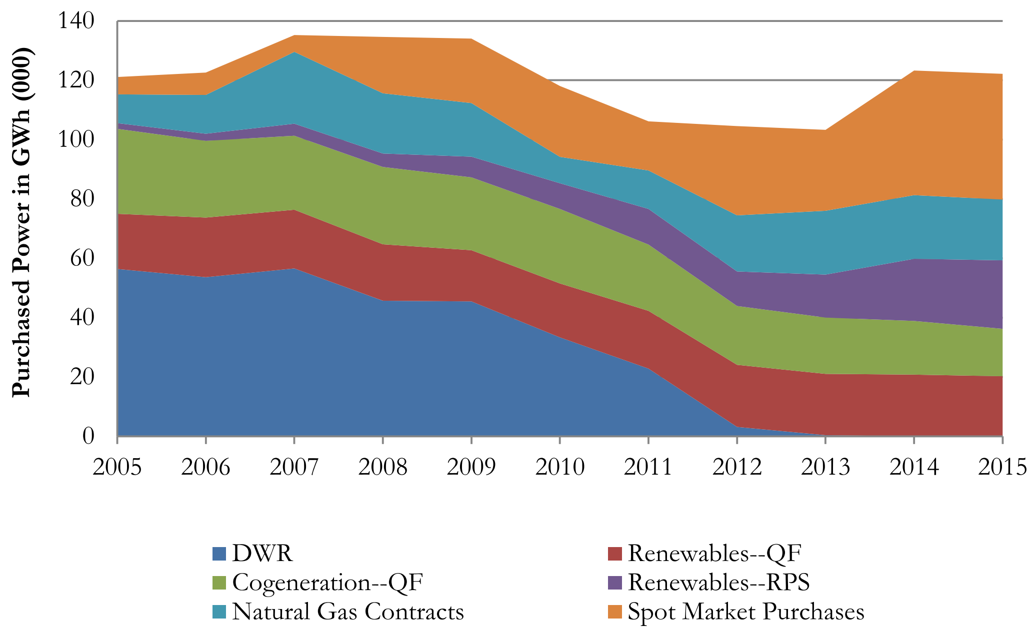
SDG&E customers.[18] As discussed further below, there is also a DWR bond charge that is collected separately in electric rates.

Qualifying Facilities (QFs)

Qualifying Facilities (QFs) are 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.[19] In 2015, the CPUC adopted an Emissions Reduction Target associated with CHP procurement of 2.72 million metric tonnes of GHG Emissions Reductions by 2020.[20]

Figures 3.2 and 3.3 break out QF supply and revenue requirements for cogeneration and renewable energy. Since 2005 the total energy supply provided by all QFs, cogeneration and renewable has decreased as older contracts expire, and the QF revenue requirement has decreased by approximately $1.4 billion.

Figure 3.2: Trends in Purchased Power Supply (GWh)

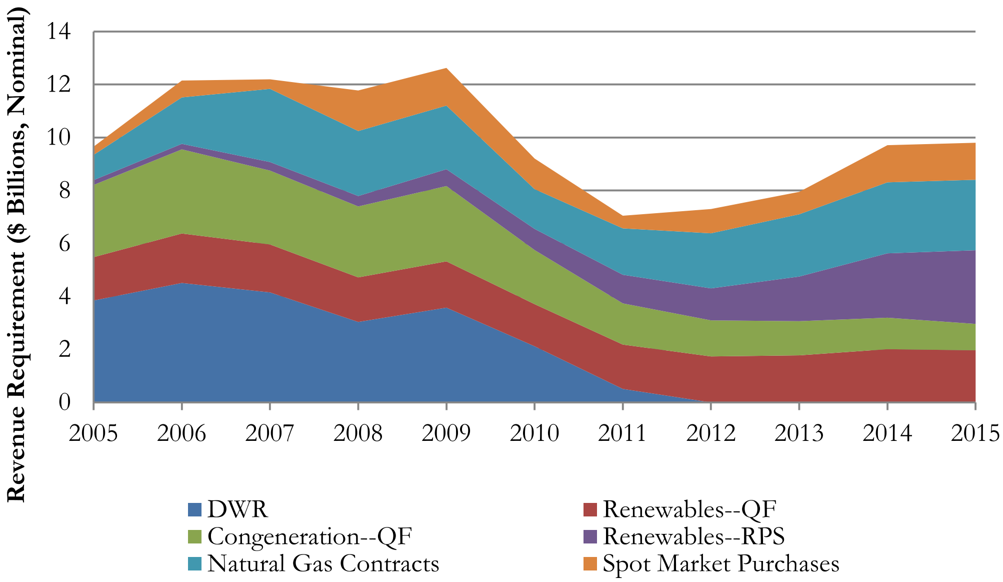


[18] D.14-12-002

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

[20] D. 15-06-028

Figure 3.3: Trends in Purchased Power Revenue Requirements



Bilateral Contracts and Capacity Contracts

Bilateral contracts are a standard method for new energy procurement. These contracts are entered into directly between the utility and an independent power supplier, which may be a generator or a trader. The utilities typically select new contracts through a Request for Offers (RFO) open solicitation process. These bilateral contracts include capacity contracts, which are necessary for the utilities to maintain a minimum 15-17% planning reserve margin for generating capacity. Capacity contracts pay generators to be available to produce power and ensure that sufficient capacity is available to meet load. Reserve margins in excess of forecasts are necessary to address unplanned outages or unexpected increases in peak loads.

Bilateral contracts represent a larger portion of the utility power procurement portfolio as the utilities replace expiring DWR contracts. Because they include both long-term and capacity contracts, bilateral contracts typically cost more than spot market purchases or short-term contracts. In comparison, under current market conditions with excess supply, spot and short term purchases are frequently less expensive because the supplier has an existing resource and is willing to sell at variable cost. With the lessons learned from the energy crisis, the CPUC and the Legislature have determined that the IOUs should not rely heavily on spot market purchases, and instead should have a more diversified portfolio. As a result, the CPUC requires long term resource planning and resource adequacy. The price of long term contracts can be thought of as a "hedging cost" or "hedging premium" over spot market prices to ensure certainty and stability of prices in the future. Since 2005, the revenue requirements from bilateral contracts have increased approximately 11% annually, and the average cost (¢/kWh) for bilateral contracts has increased by 2.8%.[21]

There are a few factors that help to explain this trend. First, in 2004, CPUC Decisions 04-10-035

[21] Bilaterals represent natural gas contracts only.

and 04-01-050 required load-serving entities to maintain a planning reserve margin of 15% above peak load for all months of the year. These requirements are primarily met through contracts with natural gas fueled generators. Because resources held in reserve are over and above expected load, they may operate infrequently, making them more expensive on a per kWh basis. Second, natural gas prices spiked in 2005 as a result of Hurricane Katrina and again in 2008, which increased the cost of the natural gas resources in those and subsequent years. However, natural gas prices have fallen considerably in recent years. Finally, many bilateral contracts are for new natural gas facilities, which are more expensive than the older, depreciated plants because of the up-front capital costs.

In addition, because approximately 10 percent of electric demand occurs for less than 150 hours per year, a significant amount of electric capacity is only needed for a few peak hours each year. Natural gas fueled generation can supply peaking and firming capacity because these units can start and ramp-up quickly. Peaking capacity generally costs more per kWh because it is used in only a few peak hours per year and thus capital costs are spread over fewer hours. Increased use of wind and solar generation can increase the need for peaking capacity to fill in when, due to variable conditions, wind and solar resources produce less energy. Recently, the utilities have added new peaking capacity to meet overall capacity requirements, particularly in transmission-constrained areas. As a result, UOG and contracted natural gas-fired generation costs are higher than would otherwise be expected in light of recent low gas prices.

Renewable Energy Procurement

SB 1078 established the Renewable Portfolio Standard (RPS) in 2002, requiring the state to meet 20% of its electricity demand from eligible renewable energy resources by 2010 and to maintain 20% renewables thereafter. Eligible resources include wind, solar photovoltaics, solar thermal, tidal wave, small hydroelectric, geothermal, biodiesel, biomass and biogas. In 2011, SB 2 increased targets to 33% by 2020.

On October 7, 2015, Governor Brown approved SB 350 (De León) or the "Clean Energy and Pollution Reduction Act of 2015."The bill revises the current RPS target to obtain 50% of total retail electricity sales from renewable resources by December 31, 2030, with interim targets of 40% by December 31, 2024, and 45% by December 31, 2027. Among other things, this bill also establishes into law: the goal of doubling the end-use energy efficiency savings from electricity and natural gas customers by 2030;, an integrated resource planning process for electric load-serving entities;, and requires the Commission to evaluate policies to develop infrastructure sufficient to overcome any barriers to the widespread deployment and use of plug-in hybrid and electric vehicles.

The RPS mandate has made renewable energy central to the state's energy procurement planning. In 2015, renewable energy revenue requirements were 33.8% of the IOUs' generation revenue requirement and 16.1% of the total revenue requirement.[22]

From 2003 to 2014, the average TOD-adjusted price of contracts approved by the CPUC has increased from 5.4 cents to 7.6 cents/kWh in nominal dollars, and decreased from 8.2 cents to 7.6 cents/kWh in real dollars.[23] One reason for this increase in nominal pricing is that the IOUs contracted with existing renewable facilities at the beginning of the RPS program and with mostly

[22] Renewable energy includes RPS eligible procurement and RPS QFs.

[23] The CPUC used the Handy- Whitman Index of Public Utility Construction Costs – Transmission Production Plant - Pacific region to calculate the real dollar amounts for year 2014.

new facilities in more recent years in order to meet the 20% and 33% RPS targets. These new facilities typically result in higher contract costs in order to recover the capital needed to develop new facilities. Having said that, the decrease in RPS contract prices in terms of real dollars indicates that the renewable market in California is robust and competitive and has matured since the start of the RPS program.

Other Power Purchases

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

- **Spot Market Purchases:** The term spot market purchases broadly refers to power that the utilities buy from the CAISO's Day-Ahead and Hour-Ahead markets 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.
- **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

Electric utilities have been regulated under California's Greenhouse Gas (GHG) Cap-and-Trade Program since January 1, 2013. As covered entities under the program, the electric utilities must buy and surrender compliance instruments - offsets and allowances - to the California Air Resources Board (ARB) to account for each unit of GHG emissions. ARB holds quarterly allowance auctions where entities can buy and sell allowances.

The Cap-and-Trade Program increases each utility's procurement costs. For electric utilities, these costs come in the form of a direct compliance obligation for utility-owned generators and generators under contract (for which they must buy and surrender compliance instruments), as well as indirect costs experienced through wholesale market transactions or power contracts with pricing terms that include GHG emission costs.

ARB allocates some allowances to electric utilities on behalf of their ratepayers. The Cap-and-Trade regulation requires the investor-owned electric utilities to sell all of these allowances at ARB's quarterly allowance auctions. The proceeds the utilities receive from the sale of GHG allowances must be used exclusively for ratepayer benefit, consistent with the goals of AB 32, 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 revenues to industrial ("emissions-intensive and trade-exposed"), small business, and residential customers. AB 693 (2015) established the Multifamily Affordable Housing Solar Roofs Program, which will be funded through allowance proceeds beginning with proceeds received during fiscal year 2016-2017.

Beginning in April 2014 (and May 2014 for PG&E), the electric utilities began introducing Cap-and-Trade-related costs into electricity rates and distributing allowance proceeds to customers. In 2014, the utilities included the forecasted 2014 costs and proceeds, plus 50 percent of the deferred 2013 costs and proceeds. The remaining 50 percent of 2013 costs and proceeds were included in 2015 rates.

In 2015, the electric IOUs collectively introduced approximately $900 million in GHG costs into rates and returned approximately $1.1 billion in allowance proceeds to customers, as shown in the table below:

Table 3.4: 2015 Summary of Greenhouse Gas Costs and Allowance Proceeds ($000)[24]

	PG&E	SCE	SDG&E	Total
GHG Costs in Rates	$333,600	$453,400	$104,300	**$891,300**
GHG Allowance Proceeds Returned to Customers	($450,000)	($561,900)	($130,100)	**($1,142,000)**

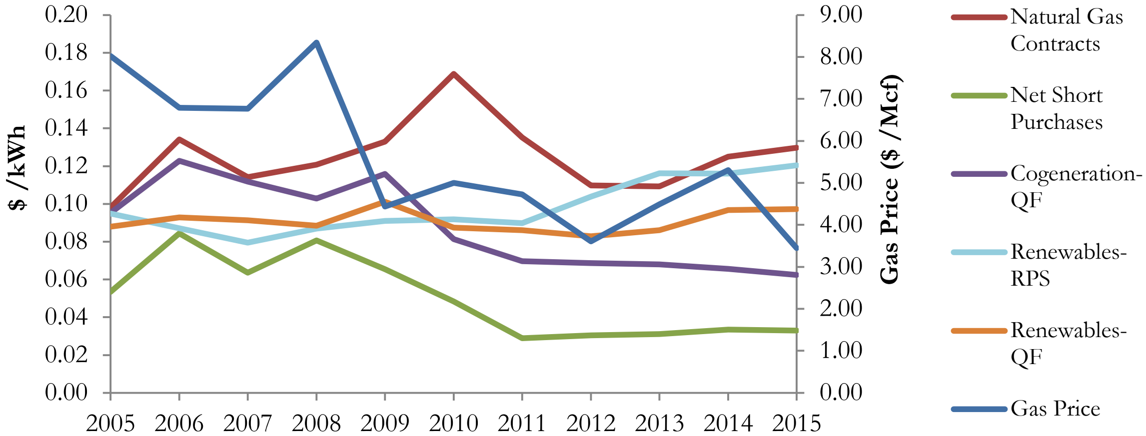
Other Factors Affecting Generation Costs

Prior sections have described many factors that cause energy generation and procurement costs to vary significantly between different types of procurement and over time. Figure 3.6 shows the average costs of various types of purchased power. Evident in this figure is the significant effect that one factor, natural gas price, has on the cost of many types of generation:

- **Natural Gas Prices:** Gas prices cause natural gas generation costs to be more volatile than other forms of generation. Spot market purchases, DWR contracts, , cogeneration QFs and spot market purchase power costs fluctuate and track with gas prices, which fell precipitously in 2008. 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. Gas prices spiked after Hurricane Katrina in 2005 (dark blue line) and are currently at historic lows, as shown in Figure 3.6. Renewables contracts generally exhibit more cost stability because they are not pegged to the gas price.

[24] Numbers for 2015 include 50 percent of deferred 2013 costs.

Figure 3.5: Average Cost for Select Purchased Power[25]



[25] The average cost for each resource represents both energy and capacity. For simplicity, this graph does not include DWR contracts or UOG gas-fired generation.

IV. DEMAND SIDE MANAGEMENT & CUSTOMER PROGRAMS

Demand Side Management (DSM) involves various programs and activities on the customer side of the meter to reduce, curtail or shift demand for electricity through energy efficiency, demand response or self-supply through distributed generation. In 2003, the CPUC and the CEC adopted the Energy Action Plan to establish goals for the state's energy strategy.[26] The plan established that cost effective energy efficiency and demand response are at the top of the loading order – the preferred means for meeting the state's growing energy needs – followed by renewable energy and distributed generation.

The revenue requirements for DSM primarily consist of financial incentives to encourage DSM activities and the administrative costs to manage these programs. In order to achieve the goals established in the Energy Action Plan, spending on DSM has experienced a 12.0% average annual increase since 2005 as the California Solar Initiative (CSI) and demand response programs were initiated and energy efficiency programs doubled in size. Benefit/cost studies have shown that in total, the collective costs of energy efficiency and demand response programs are less than the financial savings from reducing the demand for generation. In total, DSM programs combined accounted for 4.5% of the total revenue requirement (actual EE program expenditures). However the revenue requirement does not incorporate the energy savings. In addition to DSM, California also mandates customer programs to provide rate discounts and energy efficiency improvements for low-income customers.

Table 4.1: 2015 Demand Side Management and Customer Program Costs ($000)[27]

	PG&E	SCE	SDG&E	Total
Energy Efficiency	$351,311	$257,460	$104,643	$713,414
Demand Response	$63,978	$97,900	$0	$161,878
California Solar Initiative	$94,000	$82,000	$31,417	$207,416
Self-Generation Incentive Program	$29,616	$28,010	$10,035	$67,660
Low Income Energy Efficiency	$95,089	$72,737	$12,432	$180,259
Total	$633,994	$538,106	$158,527	$1,330,627

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.

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

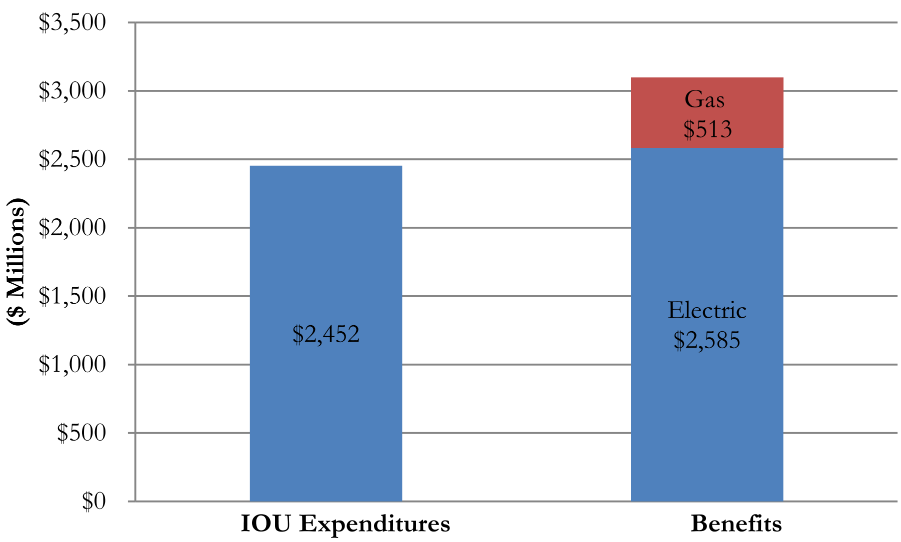
[27] Based upon the forecasted 2015 program costs.

The gas portion of the energy efficiency portfolios is funded through the gas Public Purpose Program (PPP) component of rates and 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 budget is approximately **$1 billion per year for the 2013-2015 program cycle.**[28]

The 2013-2015 energy efficiency portfolio of programs had total costs of approximately $2.45 billion over the initial 2.5 years of the three-year cycle. Programmatic efforts over this time resulted in reported program savings of 4273 GWh, 789 MW, and 107 MMtherms and lifecycle benefits of approximately $3.1 billion.[29] Like former programs, these programs continue to support residential, 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 has also supported programmatic activities targeted at the long term **transformation of consumer energy markets** through education and training, though the savings benefits associated with these efforts are difficult to quantify and the CPUC has historically elected not to attempt to do so.

Figure 4.2: Reported Expenditures and Benefits from 2013-2015 EE Program Cycle ($ Millions)[30]



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28 See D. 12-11-015 approving programs and budgets for 2013-2014 program cycle at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M034/K299/34299795.PDF .

29 See 2013-2015 energy efficiency program cycle evaluation results at http://eestats.cpuc.ca.gov/Views/EEDataPortal.aspx . Reported savings estimates are gross, as are the goals initially defined in D.04-09-060. Evaluated savings are likely to be lower and account for all savings occurring as a result of programmatic efforts (i.e. net of free-riders).

30 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.

Demand Response

Demand Response (DR) generally refers to the reduction (by end-use customers) of electricity usage during peak periods (or shifting of usage to another time period), in response to a price signal, financial incentive, environmental condition or reliability signal. DR programs save ratepayers money by **reducing the need to build power plants or avoiding the use of older, less efficient power plants** that would otherwise be necessary to meet peak demand. The reduction in peak demand also lowers the price of wholesale energy and, in turn, retail rates, and DR goals are met through customer programs and metering infrastructure upgrades. DR programs will be 'bid' as a resource in CAISO energy markets, enabling them to compete against generation bids and to be dispatched when and wherever needed by the CAISO. Future demand response programs will be designed to help integrate increasing amounts of renewable power onto the grid.

- **Demand Response Customer Programs:** These utility administered programs are primarily aimed at large commercial and industrial customers that can shed load as an immediate or day ahead response. There are programs for residential customers as well (e.g., AC Cycling). Additionally, some demand response programs are arranged by third-party operators also known as "Aggregators" or "Demand Response Providers". Customers are provided bill credits or payments to participate in the programs and customers are called to curtail load on designated peak days. DR programs can meet the needs for system reliability or peak capacity management. The costs for these programs are in administration, incentives, marketing/customer education, measurement/evaluation, IT infrastructure and pilots. In 2015, the potential capacity reductions resulting from the three electric utilities' DR programs were 2,212 MW.

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 two Distributed Generation (DG) programs that provide financial incentives to participating customers – the California Solar Initiative (CSI) and the Self-Generation Incentive Program (SGIP). 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.

California Solar Initiative (CSI)

Established in 2006, the CSI program provides either up-front incentives or performance-based payments for the installation of photovoltaic solar systems up to 1 megawatt (MW) on existing residential homes as well as existing and new commercial, industrial, government, non-profit and agricultural properties within the service territories of the IOUs. The CSI program has a budget of $2.367 billion over 10 years and a goal of reaching 1,940 MW of installed solar capacity from the general market program and two low-income programs.[31] Additionally, the CSI Thermal program,

[31] The low-income CSI programs were extended in 2015 and received an additional $54 million each, which increases the total CSI budget to $2.475 billion.

which incentivizes gas-displacing solar technologies, was established 2007 and has a budget of $250 million and a goal of installing 200,000 systems by 2018.

- Although the CSI incentives are largely exhausted, the IOUs still have a CSI revenue requirement to pay for ongoing program costs such as administration, measurement and evaluation, and marketing and outreach (e.g. quarterly solar newsletter, find a contractor tool). Additionally, CSI incentive funds are still being distributed to larger projects receiving performance-based incentives, which are paid out over a 60-month period, and to pending projects with reserved incentives once they are completed.[32]

- The program will accept new reservations until the end of 2016 or until the incentive budget is spent, whichever occurs first. The CSI program has closed in PG&E and SCE service territories and is no longer accepting applications, as the budgets there have been exhausted. In SDG&E territory the program is closed for residential applications and program funds are nearly exhausted for non-residential applications.

- As of the end of January 2016, an estimated 1,757 MW of CSI solar capacity was installed on the customer side of the meter with an additional 221 MW of capacity pending in CSI applications, indicating the program should reach its overall goal of installing 1,940 MW. A cost-effectiveness study on the CSI program was issued in April 2011.[33] This study includes forecasts that solar systems installed under the CSI program through 2012 will result in annualized life-cycle net costs to ratepayers of $150 million or more.

As of the end of January 2016, an estimated 3,252 solar thermal systems were installed on the customer side of the meter with an additional 541 systems pending in CSI Thermal applications. A Review of the Incentive Levels and Progress and the CSI Thermal Program was issued by Energy Division in January 2014.[34]

Self-Generation Incentive Program (SGIP)

Established in 2001, SGIP provides incentives to support distributed energy resources that will result in greenhouse gas (GHG) emission reductions and peak demand reductions.
With 1,101 completed projects, totaling 434 megawatts of capacity,[35] SGIP is one of the longest-running DG incentive programs in the country.

- The program was reauthorized by SB 861 (2014) to continue through 2020, and will continue to provide GHG and peak demand reduction benefits well into the future. For larger 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.

- Qualifying technologies include wind turbines, waste heat to power technologies, pressure reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells and

[32] The IOUs' respective annual revenue requirements for the CSI program were most recently revised and approved in D.11-07-031 (p.12).

[33] *See* ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/csi/CSI%20Report_Complete_E3_Final.pdf.

[34] *See* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4259

[35] *See* SGIP Program Statistics, here: https://energycenter.org/programs/self-generation-incentive-program/program-statistics. Data as of February 5, 2016. Does not include solar PV installations, which were incentivized under SGIP prior to CSI.

advanced energy storage systems. A new cost-effectiveness study of SGIP was issued in October 2015.[36] An updated Annual SGIP Impact Evaluation was also released in April 2015.[37]

Net Energy Metering (NEM)

Residential and commercial customers who install small RPS-eligible generation facilities (1 MW or less) to serve all or a portion of onsite electricity needs are eligible for the state's NEM program. NEM allows customer-generators to receive a full retail-rate bill credit for energy generated by their on-site system that is fed back into the utility grid during times when on-site generation exceeds a customer's energy demand. The credit is used to offset the customers' electricity bills and may be rolled over to subsequent billing periods for up to a year. In January 2016, the CPUC approved a decision adopting a NEM successor tariff for customers receiving NEM service after each IOU reaches its 5% NEM capacity cap. As part of this process, the CPUC developed the NEM Public Tool, which modeled the costs and benefits of proposed successor tariffs.[38] The CPUC last released an updated NEM cost-benefit study in October 2013, which found that NEM would result in non-participant ratepayer costs of approximately $1 billion per year by 2020.[39] The study also concluded that NEM customers were paying, on average, close to the utility's cost of providing service.

Low-Income Programs

IOUs provide two ratepayer-funded programs for qualifying low-income customers meeting the income limits at or below 200% of federal poverty guideline. The California Alternate Rates for Energy program (CARE) offers rate discounts off low income customers' energy bills and the Energy Savings Assistance program (ESA) installs energy-efficient measures in income-qualified homes at no-cost to the customer.

Table 4.3: 2015 Low Income Program Costs ($000)[40]

	PG&E	SCE	SDG&E	Total
CARE Subsidy	$565,541	$372,593	$114,917	$1,053,052
CARE Administrative Expenses	$12,794	$7,020	$4,460	$24,274
Low Income Energy Efficiency	$95,089	$ 72,737	$12,432	$180,259
Total	$673,424	$452,350	$131,810	$1,257,584

[36] *See* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

[37] *See* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7909

[38] *See* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=5817

[39] *See* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=4292

[40] Based upon the forecasted 2015 program costs.

California Alternate Rates for Energy (CARE)

The CARE program was established in 1989 by P.U. Code Sections 739.1 and 739.2, authorizing a 15% rate discount for qualifying low-income customers off their energy bills. In 2001, the minimum CARE rate discount was increased from 15% to 20% by CPUC Decision 01-06-010. In October 2013, AB 327 was passed requiring the IOUs to restructure the CARE rates and to set an effective electric rate discount between 30-35%.

CARE costs have two components—the CARE program management cost and the cost of the subsidy itself. CARE program management costs total approximately $30 million per year. The CARE subsidy is a much larger amount. All CARE costs, both administrative and subsidy are paid for by non-CARE customers. 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.

The cost of the PG&E CARE subsidy in 2015 was approximately $558 million, compared to $372 million for SCE and $76 million for SDG&E. A major reason for this discrepancy is the difference between CARE effective discounts among the three utilities (along with the fact that SDG&E has a significantly lower customer base). In 2015, PG&E's CARE effective discount was 37.6%, whereas SCE's was 32% and SDG&E's was 40%. In compliance with AB 327 and D.15-07-001, the effective discount will be reduced to 35% for PG&E, will remain at 32.5% for SCE and will be reduced to 35% for SDG&E. These reductions will take place gradually between now and 2020.

Energy Savings Assistance Program (ESA)[41]

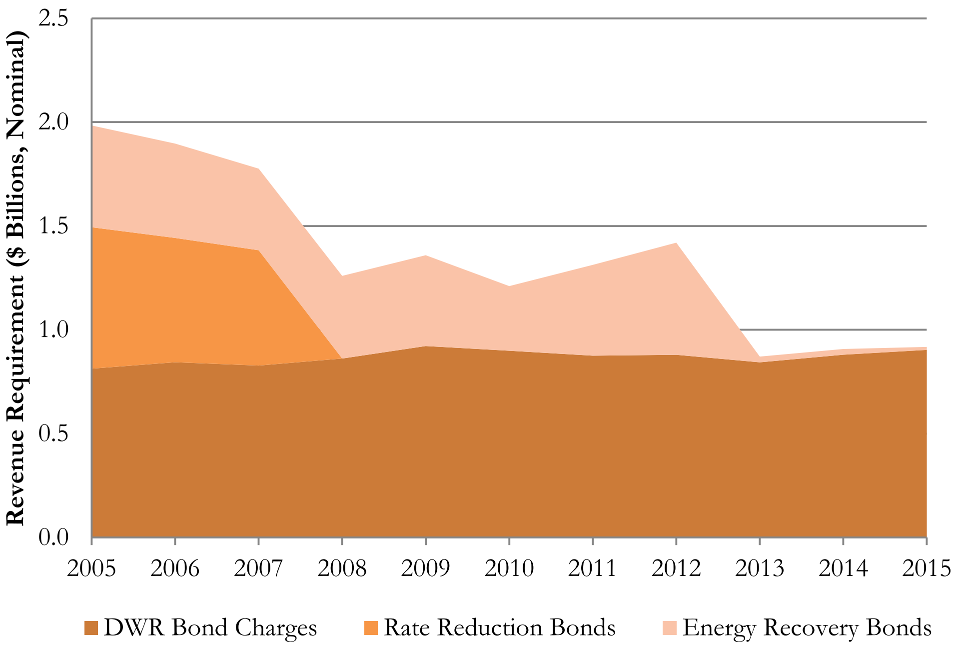
The ESA program is mandated by Public Utilities Code 2790. The ESA program has the objective delivering energy efficiency to income-qualified customers, to reduce financial hardships. Programmatically, the program balances cost effectiveness with the customers' health, comfort and safety. The program provides free and low-cost home weatherization, energy efficient appliances (including lighting, heating, and other appliances) and energy outreach education services. Program delivery is coordinated amongst both natural gas and electric utility services. Enrollment in rate assistance programs, such as CARE or Lifeline or water utility programs are automatically coordinated). In 2015, approximately 20-30% of all IOU customers were enrolled in a low-income assistance program. ESA is available to customers living in all housing types (single family, multifamily and mobile homes), regardless of whether they are homeowners or renters. By statute, the program targets high energy users (400-600% above baseline) and mandates it for CARE recipients who are 600% above baseline. In 2015, the ESA program accounted for approximately 0.6% of the IOUs' total revenue requirement.

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

V. BONDS AND REGULATORY FEES

During the era of electric restructuring, the State and the utilities issued a series of bonds in order 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 $2 billion in 2004 to $0.9 billion in 2015, as illustrated below.

Figure 5.1: Trends in Bond Expenses



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%.

Department of Water and Resources (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 June 30, 2015, a $5.6 billion balance remained outstanding on the DWR bonds.[42] The balance is scheduled to be repaid by 2022.

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

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[42] Department of Water Resources Electric Power Fund Financial Statements, June 30, 2015 p. 25, available at http://www.cers.water.ca.gov/pdf_files/101615_epf.pdf

Table 5.2: 2014 Bond Expenses ($000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges	$404,945	$398,572	$94,812	$898,329
Rate Reduction Bonds	-	-	-	-
Energy Recovery Bonds	$14,231	-	-	$14,231
Total	**$419,176**	**$398,572**	**$94,812**	**$912,560**

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. In total, this entire category of expenses accounted for about 2.5% of the 2015 revenue requirement.

Table 5.3: 2014 Regulatory Fees ($000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC Reimbursement fee*	$20,597	$20,840	-	$41,437
Catastrophic Events Memorandum Acct.	-	-	-	-
Franchise Fees & Uncollectible Surcharge	$138,068	$125,291	$81,354	$344,713
Environmental Enhancement	-	-	-	-
Electricity Program Investment Charge (EPIC)	$85,139	$69,846	$14,955	$169,939
Nuclear Decommissioning**	$106,570	-	$8,070	$114,640
Spent Nuclear Fuel	-	$6,525	$1,087	$7,612
Energy Efficiency Incentive Awards***	$29,728	$21,613	-	$51,341
Total	**$380,102**	**$244,114**	**$105,466**	**$729,682**

* SDG&E did not include the CPUC fee in the revenue requirements reported here, but does collect this fee as a separate charge on the utility bill.

** SCE records its Nuclear Decommissioning expenses as a balancing account adjustment.

***SDG&E records its Energy Efficiency Incentive Awards as a balancing account adjustment.

Definition of Fees

- **CPUC Reimbursement Fee:** This is the annual fee to be paid by utilities to fund their regulation by the Commission (Public Utilities (PU) Code Section 401-443). The surcharge to recover the cost of that fee is ordered by the Commission under authority granted by PU Code Section 433.
- **Catastrophic Events Memorandum Account**: 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.
- **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.
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected.
- **Environmental Enhancement:** A (PG&E only) program established by the PG&E bankruptcy settlement to provide environmental enhancement of a dedicated watershed, which was donated to a public trust as part of the settlement.
- **Electricity Program Investment Charge (EPIC):** In a series of decisions, the CPUC determined that it had a compelling interest in providing ongoing support for the development and deployment of new and emerging energy technologies, despite the sunset of the Public Goods Charge. To address this gap, in May of 2012, the CPUC adopted D.12-05-037, establishing a framework for the deployment of funds to provide ongoing support for the development and deployment of next generation clean energy technologies. The EPIC Program was subsequently codified by the legislature in Senate Bill 96 (Statutes of 2013). The distribution of these funds is administered primarily by the California Energy Commission.
- **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.

VI. 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 Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E). Unlike the process for electric utilities, the CPUC does not set an annual authorized revenue requirement for natural gas utilities' procurement costs. Core gas procurement costs are recovered in utility gas procurement rates which are adjusted monthly.

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

Table 6.1: 2015 Gas Revenue Requirement Summary by Key Components ($000)

	PG&E	SoCalGas	SDG&E	Total
Core Procurement	$1,298,757	$951,033	$131,006	$2,380,796
Transportation	$2,500,926	$2,511,953	$378,037	$5,390,916
Public Purpose Programs	$271,726	$363,588	$34,753	$670,067
Totals	$4,071,409	$3,826,574	$543,796	$8,441,779

For 2015, total natural gas utility costs increased by 0.2% from 2014, which is less than the 7.3% increase from 2013 to 2014. PG&E's total natural gas utility costs increased by 9.7%, but SoCalGas's costs declined by 8.1% and SDG&E's costs declined by 1.4%.

As the tables below show, gas utility transportation and distribution costs have increased by 12.6% from 2014 to 2015 as gas utilities place greater emphasis on safety and replacing aging infrastructure. Procurement costs dropped 22.4% due to the decrease in natural gas prices. Natural gas public purpose program costs rose by 15.1% from 2014 to 2015, mostly due to California Alternative Rates for Energy (CARE) and low-income energy-efficiency programs, both of which are designed to subsidize low-income households' utility bills.

Figure 6.2: Trends in Gas Utility Revenue Requirements ($000)

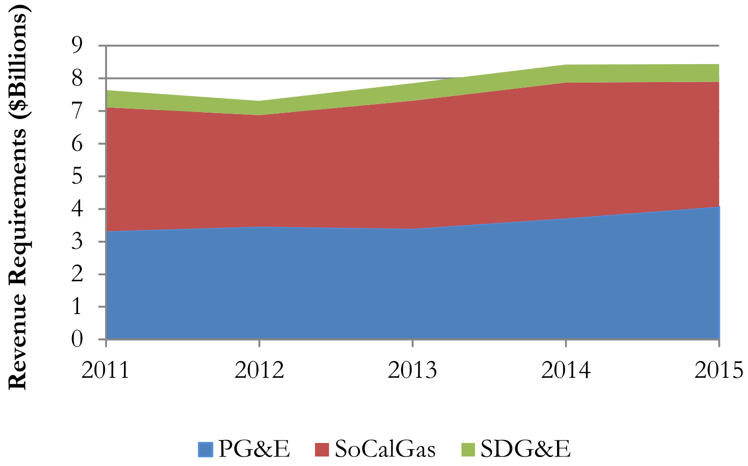

Figure 6.3: Trends in Gas Utility Revenue Requirement Components ($000)

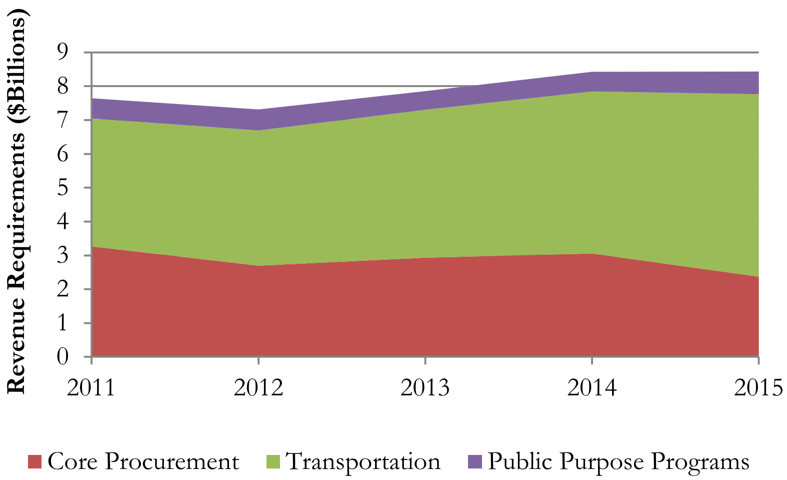

Table 6.4: Historic Gas Utility Revenue Requirements Since 2011 ($000)

	2011	2012	2013	2014	2015
Core Procurement	$3,265,766	$2,696,629	$2,932,620	$3,0553,256	$2,371,796
Transportation	$3,781,343	$3,994,102	$4,370,631	$4,788,140	$5,390,916
Public Purpose Programs	$596,016	$624,657	$551,281	$581,915	$670,067
Total	$7,643,125	$7,312,388	$7,854,532	$8,425,311	$8,432,779

Table 6.5: Percent Change in Gas Utility Revenue Requirements Since 2011

	Core Procurement	Transportation	Public Purpose Programs
PG&E	-15%	63%	3%
SoCalGas	-38%	27%	26%
SDG&E	-37%	37%	-24%

Core Gas Procurement

The major natural gas utilities recover core customer procurement costs through a rate component called the gas procurement rate. The gas procurement rate is changed every month to reflect the most current price of natural gas. The procurement rates are changed routinely through utility advice letter filings with the CPUC. Core gas procurement costs in 2015 decreased by 22.4% from 2014, due to a drop in natural gas prices. Overall, natural gas core procurement costs have decreased by 27% since 2011. In 2015, core gas procurement costs accounted for about 28% of the total utility costs.

Core gas customers – primarily residential and small commercial accounts – in California have the option to choose between utility gas procurement service and gas procurement service from other entities called Core Transport Agents (CTAs). In 2013, Core Transport Agent service grew in popularity, particularly in PG&E's service territory, prompting the passage of a new bill to regulate CTAs under the California Public Utilities Code. However, despite the increase in CTA popularity, the vast majority (over 80%) of core gas customers still receive utility gas procurement service. Almost all larger, "noncore" natural gas consumers--industrial customers or electric generators--procure their own natural gas supplies using non-utility suppliers. Thus, the procurement costs shown in this section reflect only the costs to the utilities 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. 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 fallen 35% from 2009 to 2015.

Neither the Commission nor the FERC regulates the wholesale price of natural gas. The decrease in the price of natural gas has resulted from developments in the natural gas commodity market.

Figure 6.6: Revenue Requirements for Utility Natural Gas Core Procurement ($000)

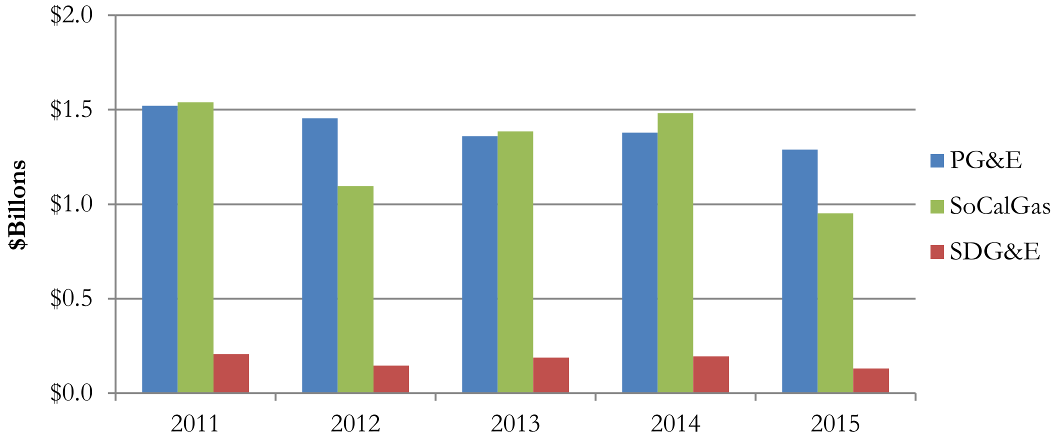

Table 6.7: Historic Revenue Requirement for Core Procurement ($000)

	2009	2010	2011	2012	2013	2014	2015
PG&E	$2,020,976	$2,327,868	$1,520,282	$1,455,016	$1,359,218	$1,378,948	$1,289,757
SoCalGas	$1,441,099	$1,656,802	$1,538,869	$1,095,871	$1,385,335	$1,481,448	$951,033
SDG&E	$185,434	$202,211	$206,615	$145,742	$188,067	$194,860	$131,006
Total	$3,647,509	$4,186,881	$3,265,766	$2,696,629	$2,932,620	$3,055,256	$2,371,796

Gas Transmission, Distribution and Storage Costs

The Commission 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. In 2015, gas transportation costs increased by 0.2% and represented about 64% of total utility gas costs. The bulk of these revenue requirements are primarily determined by the CPUC in two types of major proceedings: 1) general rate cases for PG&E, SoCalGas and SDG&E and 2) PG&E transmission and storage proceedings.

The following table shows that increases in total authorized revenue requirements for transmission, distribution, storage, and customer services, combined under the "transportation" category, have increased by 45% from 2010 to 2015. Such costs increased by 62%, 34%, and 26% for PG&E, SoCalGas, and SDG&E, respectively, from 2010 to 2015. With the recent emphasis on safety and replacement of aging infrastructure, the CPUC has authorized increased revenue requirements for all of the three major gas utilities with respect to transmission and distribution.

Figure 6.8: Revenue Requirements for Utility Natural Gas Transmission, Distribution, and Storage ($000)

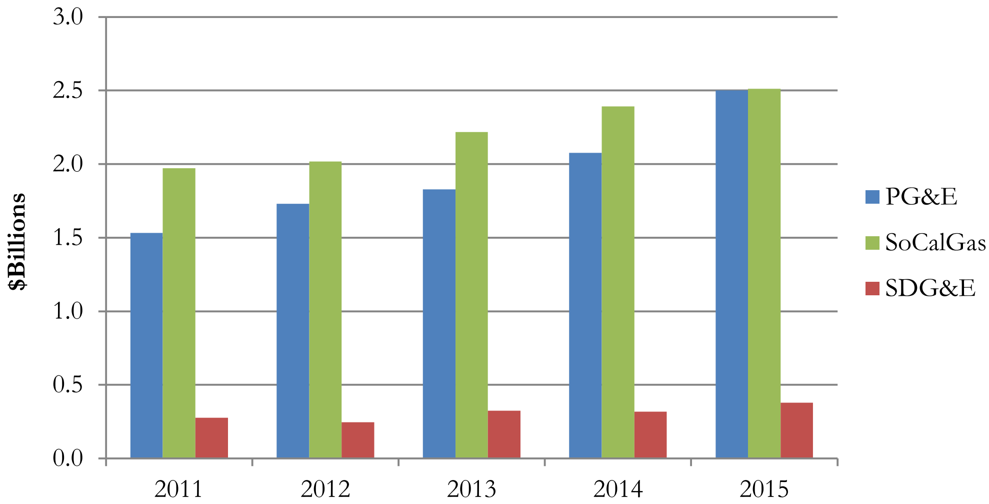

Table 6.9: Historic Revenue Requirement for Transportation ($000)

	2010	2011	2012	2013	2014	2015
PG&E	$1,541,446	$1,533,332	$1,731,021	$1,828,380	$2,076,507	$2,500,926
SoCalGas	$1,880,826	$1,971,438	$2,018,108	$2,218,229	$2,392,986	$2,511,953
SDG&E	$299,774	$276,573	$244,973	$324,022	$318,647	$378,037
Total	$3,722,046	$3,781,343	$3,994,102	$4,370,631	$4,788,140	$5,390,916

Gas Public Purpose Program (PPP) Costs

The Commission also authorizes costs for three main categories of gas PPPs: energy efficiency (EE) and low-income EE, the California Alternate Rate for Energy (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 significantly since 2008, but are a relatively small part of total costs.

Costs authorized by the CPUC in 2015 for natural gas PPPs increased by 15.1% from 2014. Increased costs were driven primarily by low-income programs: Low-Income Energy Efficiency and California Alternate Rates for Energy (CARE). Gas PPP costs made up 7.9% of total utility costs in 2015.

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.

Figure 6.10: Revenue Requirements for Utility Public Purpose Programs ($000)

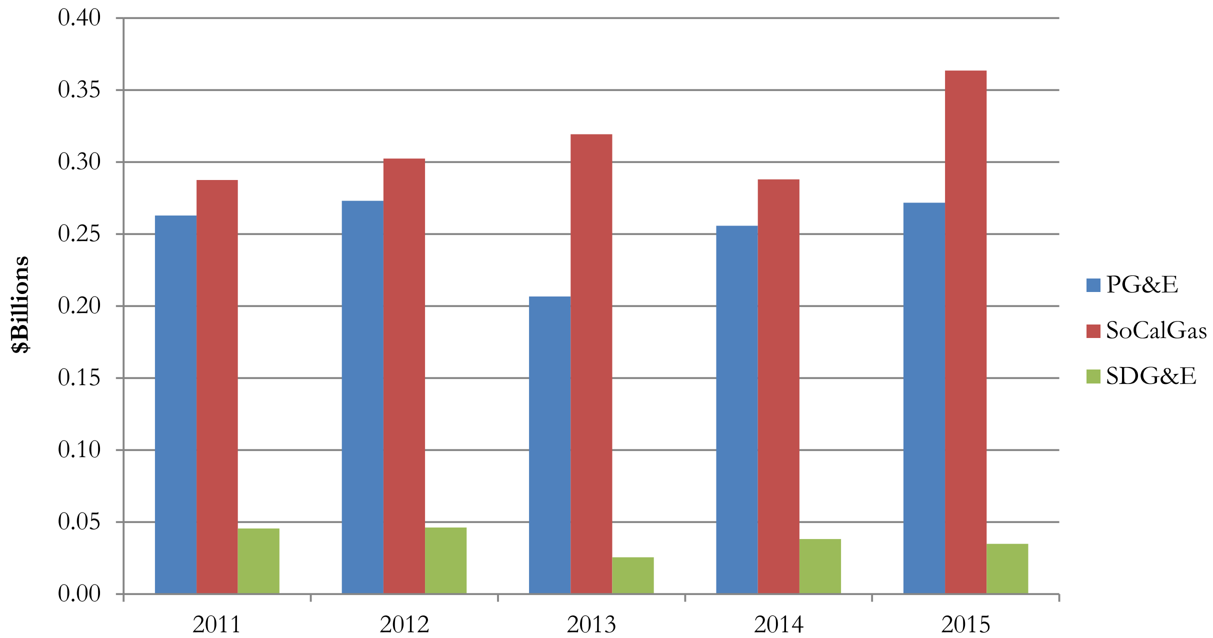

Table 6.11: Historic Revenue Requirement for Public Purpose Programs ($000)

	2009	2010	2011	2012	2013	2014	2015
PG&E	$222,589	$246,480	$262,869	$273,008	$206,563	$255,754	$271,726
SoCalGas	$271,411	$269,412	$287,564	$302,506	$319,252	$287,906	$363,588
SDG&E	$37,482	$37,568	$45,583	$46,583	$25,466	$38,255	$34,753
Total	$531,482	$553,460	$596,016	$622,097	$551,281	$581,915	$670,067

Appendix A: 2015 Electric Revenue Requirement ($000)

	Mandated by Federal/State Statute	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**7,207,668**	**6,896,260**	**1,617,838**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	348,936	2,674,431	48,151
General Rate Case Revenues		CPUC Decisions	1,998,784	1,297,855	231,261
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	2,020,553	Included with Qualifying	590,260
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,836,641	2,925,374	696,005
Other		CPUC Decisions, Resolutions	2,755	(1,400)	-
Transmission Total			**1,482,664**	**923,707**	**470,893**
Reliability Services	FERC Order 459		10,732	(85,755)	4,780
Transmission Access Charge	FERC		219,659	108,987	(267,203)
Transmission Owner Rate Case Revenues	FERC		1,294,362	910,155	739,625
Other - FERC Rate Case Revenues	FERC		(42,089)	(9,680)	(11,824)
Other			-	-	5,514
Distribution Total			**4,534,755**	**4,433,600**	**1,201,767**
General Rate Case Revenues		CPUC Decisions	4,534,755	4,433,600	1,201,767
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**162,769**	**23,506**	**8,560**
Demand Side Management and Customer Programs Total*			**721,245**	**518,077**	**313,267**
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,616	28,010	10,035
California Solar Initiative		CPUC Decisions	94,000	82,000	31,417
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	59,356	97,900	20,730
Energy Efficiency, PU Code 399.8	PUC Section 399.8	CPUC Decisions, E-3792	119,446	257,460	-
Energy Efficiency (non-PUC 399.8)			248,175	-	98,643
Electricity Program Investment Charge		CPUC Decisions	72,567	69,846	14,955
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	95,089	72,737	12,432
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	2,997	(26,239)	4,460
Renewables	PUC Section 399.8	CPUC Resolution E-3792	-	-	
Other PPP		CPUC Decisions, Resolutions	-	(63,636)	120,595
Other Regulatory Total			**(427,234)**	**(12,913)**	**465,987**
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	-	-	-
Hazardous Substance Mechanism		CPUC Decisions	20,174	-	1,915
CPUC Fee	PUC Section 431	CPUC Resolution M-4819	20,597	20,648	-
Four Corners Gain on Sale (SCE only)		CPUC Decisions	-	(82,960)	-
Other		CPUC Decisions, Resolutions	(468,006)	49,399	464,072
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(85,503)**	**(124,600)**	**(41,541)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**404,945**	**398,572**	**94,812**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**194,496**	**(424,476)**	**18,937**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(437,110)**	**-**	**-**
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	**10,696**	**10,940**	**17,779**
Electric Total			**13,765,151**	**12,636,310**	**4,116,137**

*These items are recovered in the Delivery component of rates.

Appendix A: 2014 Electric Revenue Requirement ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**6,473,619**	**7,380,787**	**1,706,181**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	459,513	2,674,431	53,754
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	0	0	0
General Rate Case Revenues		CPUC Decisions	1,611,148	1,781,282	368,213
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,858,438	Included with Qualifying Facilities	523,230
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,541,479	2,925,374	760,984
Other		CPUC Decisions, Resolutions	3,041	(300)	0
Transmission Total			**1,482,838**	**860,983**	**362,138**
Reliability Services	FERC Order 459		24,670	19,402	5,345
Transmission Access Charge	FERC		479,256	70,873	(213,536)
Transmission Owner Rate Case Revenues	FERC		978,912	820,923	575,324
Other - FERC Rate Case Revenues	FERC		0	(50,215)	(9,404)
FF&U			0	0	4,409
Distribution Total			**4,235,581**	**4,305,474**	**1,468,603**
AMI/Smart Meter		CPUC Decisions	114,570	0	0
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,839	28,010	10,035
California Solar Initiative		CPUC Decisions	85,917	73,990	29,667
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	65,849	77,192	19,503
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
General Rate Case Revenues		CPUC Decisions	3,880,425	4,473,656	1,171,235
Hazardous Substance Mechanism		CPUC Decisions	22,429	0	1,595
Energy Efficiency Incentives		CPUC Decisions	0	0	0
Low Emission Vehicle Program	PUC Section 740.3 & 740.8	CPUC Decisions, Resolutions	0	0	0
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	20,863	20,840	0
Climate Smart			0	0	0
Other		CPUC Decisions, Resolutions	15,691	(347,374)	236,568
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**44,161**	**46,488**	**9,239**
Public Purpose Programs Total			**493,568**	**293,738**	**244,458**
Energy Efficiency		CPUC Decisions	333,274	238,904	95,435
Electricity Program Investment Charge		CPUC Decisions	0	32,502	0
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	94,893	39,477	12,423
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	(648)	12,412	4,317
Renewables	PUC Section 399.8	CPUC Resolution E-3792	0	34,080	14,256
PPP Balancing Acct			66,049	(63,636)	118,028
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(1,171)**	**(26,700)**	**(27,000)**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**398,573**	**388,795**	**92,469**
AB1890 Rate Reduction Bonds	AB 1890, PUC Section 368(a), 840-847	CPUC Decisions, Resolutions	**0**	**0**	**0**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**276,708**	**(424,476)**	**26,499**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(133,476)**	**0**	**0**
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**6,868**	**13,611**
Electric Total			**13,270,401**	**12,852,798**	**3,896,198**

Appendix A: 2013 Electric Revenue Requirement ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total			**5,663,379**	**6,139,534**	**1,337,382**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	342,666	1,994,150	56,002
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	0	0	0
General Rate Case Revenues		CPUC Decisions	1,631,743	2,139,002	409,277
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	1,249,663	0	186,041
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,469,317	2,007,185	686,062
Other		CPUC Decisions, Resolutions	3,204	(802)	0
Transmission Total			**1,280,210**	**892,080**	**412,843**
Reliability Services	FERC Order 459		(11,480)	0	362
Transmission Access Charge	FERC		343,620	0	(232,548)
Transmission Owner Rate Case Revenues	FERC		976,570	892,080	646,771
Other - FERC Rate Case Revenues	FERC		(28,499)	0	(1,741)
Distribution Total			**4,449,817**	**4,260,078**	**1,168,924**
Advanced Metering Infrastructure		Report	0	0	0
Smart Meter			130,451	0	0
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	30,566	28,324	10,819
California Solar Initiative		CPUC Decisions	85,917	74,858	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	79,240	78,059	16,676
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	106,304	0	0
General Rate Case Revenues		CPUC Decisions	3,969,738	4,259,159	1,141,929
Hazardous Substance Mechanism		CPUC Decisions	16,936	9,613	(500)
Energy Efficiency Intentives		CPUC Decisions	22,478	0	0
Low Emission Vehicle Program	PUC Section 740.3 & 740.8	CPUC Decisions, Resolutions	0	0	0
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	20,557	20,460	0
Climate Smart			0	0	0
Other		CPUC Decisions, Resolutions	10,108	628	0
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**44,550**	**11,877**	**(7,061)**
Public Purpose Programs Total			**481,736**	**640,800**	**134,719**
Energy Efficiency	PUC Section 399.8	CPUC Decisions, E-3792	295,339	341,539	46,792
Electricity Program Investment Charge	PUC Section 399.8	CPUC Resolution E-3792	0	32,502	0
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	92,139	72,640	12,304
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	18,548	66,549	61,368
PPP Balacing Acct			75,710	61,083	0
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**43,014**	**(69,222)**	**36,000**
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**393,032**	**374,944**	**92,518**
AB1890 Rate Reduction Bonds	AB 1890, PUC Section 368(a), 840-847	CPUC Decisions, Resolutions	**0**	**0**	**0**
Ongoing Competition Transition Charge	AB 57, PUC Section 367(a) & 369	CPUC Decisions	**353,004**	**81,671**	**60,192**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**(16,300)**	**0**	**0**
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	**0**	**0**	**8,148**
Electric Total			**12,762,493**	**12,331,763**	**3,243,665**

Appendix B: 2015 Gas Revenue Requirement ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**1,298,757**	**131,006**	**951,033**
Core Gas Supply Portfolio		CPUC Decisions	958,172	131,006	943,783
Other		CPUC Decisions	331,551	0	0
10/20 Winter Gas Savings		CPUC Resolutions	0	0	0
Core Gas Hedging		Report	7,636	0	0
Incentive Mechanism		Report	1,398	0	7,250
Transportation Total			**2,500,926**	**378,037**	**2,511,953**
Distribution		CPUC Decisions	2,013,714	337,929	2,187,256
Transmission		CPUC Decisions	453,878	0	0
Advanced Metering Infrastructure		Report	14,793	0	115,600
Smart Meter			0	0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	6,525	788	8,137
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	5,211	1,926	0
Annual Earning Assessment (AEAP)		CPUC Decisions	7,119	0	5,599
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	41,872
Haz Substance Mechanism (HSM)		CPUC Decisions	46,555	1,406	2,760
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	10,213
Core Pricing Flexibility Program		CPUC Decisions	0	0	974
Non core competitive load growth program		CPUC Decisions	0	0	391
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	(14,524)	20,654	29,475
CPUC Fee	PUC Section 431	Resolution M-4816	3,210	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	9,794	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	13,426	1,977	34,204
AB 32 Cap-And-Trade			2,771	(387)	10,684
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**271,726**	**34,753**	**363,588**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	88,142	(573)	81,770
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	76,324	15,110	132,417
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	11,094	1,554	13,672
Calif Alternate Rates for Energy (CARE) Program			96,166	18,662	135,729
GAS TOTAL			**4,071,409**	**543,796**	**3,826,574**

Appendix B: 2014 Gas Revenue Requirement ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**1,378,948**	**194,860**	**1,481,448**
Core Gas Supply Portfolio		CPUC Decisions	1,020,945	194,860	1,467,738
Other		CPUC Decisions	334,233	0	0
10/20 Winter Gas Savings		CPUC Resolutions	8,941	0	0
Core Gas Hedging		Report	4,500	0	0
Incentive Mechanism		Report	10,329	0	13,710
Transportation Total			**2,076,507**	**314,076**	**2,360,179**
Distribution		CPUC Decisions	1,556,022	273,563	2,041,078
Transmission		CPUC Decisions	411,696	7,972	31,664
Advanced Metering Infrastructure		Report	15,929	0	102,754
Smart Meter				0	0
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	6,480	773	26,141
Climate Smart			0	0	0
Calif Solar Initiative (CSI)		CPUC Decisions	4,598	3,643	0
Annual Earning Assessment (AEAP)		CPUC Decisions	3,982	0	3,033
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	61,647
Haz Substance Mechanism (HSM)		CPUC Decisions	51,776	3,646	0
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	9,940
Core Pricing Flexibility Program		CPUC Decisions	0	0	598
Non core competitive load growth program		CPUC Decisions	0	0	671
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	(2,673)	21,874	55,064
CPUC Fee	PUC Section 431	Resolution M-4816	3,210	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	3,207	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	17,320	2,053	27,589
AB 32 Cap-And-Trade			4,960	552	8,315
Public Purpose Program Surcharges Total	PUC Sections 399.8, 890-900	CPUC Decisions	**255,754**	**38,255**	**287,906**
Energy Efficiency (EE) Programs	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	82,672	10,604	52,471
Low Income Energy Efficiency (LIEE)	PUC Sections 740, 890-900	CPUC Decisions	69,107	10,093	120,506
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	10,883	1,338	12,513
Calif Alternate Rates for Energy (CARE) Program			93,092	16,220	102,416
GAS TOTAL			**3,711,209**	**547,191**	**4,129,533**

Appendix B: 2013 Gas Revenue Requirement ($000)

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
Core Procurement Total			**1,359,218**	**188,067**	**1,385,335**
Core Gas Supply Portfolio		CPUC Decisions	985,735	188,067	1,379,504
Other		CPUC Decisions	354,320	0	0
10/20 Winter Gas Savings		CPUC Resolutions	(498)	0	0
Core Gas Hedging		Report	19,661	0	0
Incentive Mechanism		Report	0	0	5,831
Transportation Total			**1,828,380**	**324,022**	**2,218,229**
Distribution		CPUC Decisions	1,147,644	298,712	1,945,958
Transmission		CPUC Decisions	502,256	0	0
Advanced Metering Infrastructure		Report	93,402	0	86,150
Self Gen Inc Prog (SGIP)	PUC Section 379.6 (a)	CPUC Decisions	5,760	814	31,528
Calif Solar Initiative (CSI)		CPUC Decisions	6,365	1,362	0
Annual Earning Assessment (AEAP)		CPUC Decisions	3,757	0	5,582
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	0	47,295
Haz Substance Mechanism (HSM)		CPUC Decisions	39,095	(2,085)	9,633
Non Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions	0	0	9,670
Core Pricing Flexibility Program		CPUC Decisions	0	0	454
Non core competitive load growth program		CPUC Decisions	0	0	857
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, CPUC Decisions, Resolutions	(3,190)	22,617	54,589
CPUC Fee	PUC Section 431	Resolution M-4816	3,210	0	0
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	2,764	0	0
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	11,883	2,120	21,794
AB 32 Cap-and-Trade	CA H&S Code Section 38597, CCR Title 17 Division 3	CPUC Decisions	15,434	482	4,719
Public Purpose Program Surcharges Total			**206,563**	**25,466**	**319,252**
Energy Efficiency (EE) Programs	PUC Sections 399.8, 890-900	CPUC Decisions	53,002	1,510	42,618
Low Income Energy Efficiency (LIEE)	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	55,979	9,836	146,870
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 740, 890-900	CPUC Decisions	10,223	1,351	10,969
Calif Alternate Rates for Energy (CARE) Program	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	87,359	12,769	118,795
GAS TOTAL			**3,394,161**	**537,555**	**3,922,816**