California Public Utilities Commission

Electric and Gas Utility Cost Report

Public Utilities Code Section 747 Report to the Governor and Legislature

April 2014

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Figures and Tables

Figures and Tables (cont.)

I. Introduction

Enacted as Assembly Bill (AB) 67 in 2005, Public Utilities Code 747(b) requires the California Public Utilities Commission (CPUC or the Commission) to prepare a written report on the costs of programs and activities conducted by the four major electric and gas companies regulated by the Commission. This legislation was enacted in part to determine the effect of various legislative and administrative mandates, and because rates did not decrease as much as expected after the imposition of charges to address the energy crisis of 2000 and 2001.

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 commission and its annual cost to ratepayers.
3) Energy purchase contract costs and bond-related costs incurred pursuant to Division 27 of the Water Code.
4) All other aggregated categories of costs currently recovered in retail rates as determined by the commission.

This report is submitted by the Commission to fulfill these statutory requirements.

Background

The State of California has been a national leader in electric and gas 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. 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.

Similar to the 2012 AB 67 Report, this report provides a detailed narrative of various energy policies in California to provide the context necessary to understand what drives electric and gas rates. The report presents a breakdown of the major components that contribute to electric and gas rates, with charts and tables showing how these costs and rates have varied since 2003.

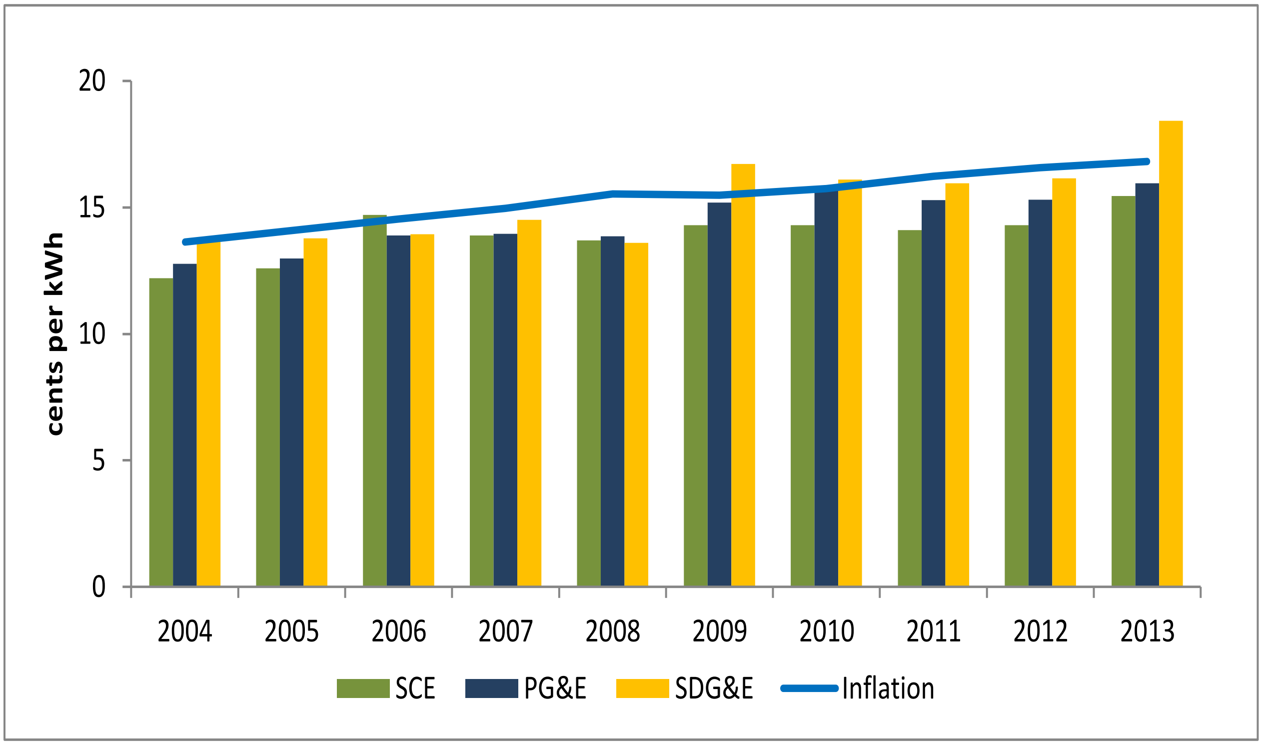
The Report presents an analysis of the authorized revenue requirements for the four major California investor-owned utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCalGas). "Authorized revenue requirements" are the revenues that the utilities are authorized to collect from customers. Using sales forecasts, rates are then set to collect the authorized revenue requirements. To the extent that actual sales differ from forecasted sales, the utilities may collect more or less than the authorized revenue requirements. 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 "true-up" ensures that the utilities only collect their authorized revenue requirements.

Overview

Electric Utility Costs

- **System average rate increases have roughly tracked inflation.** Between 2004 and 2013, system average rates have increased at an annual average of approximately 1.5%, compared with an average annual inflation rate of 2.4%. Figure 1 shows the trend in average electric rates for SCE, PG&E, and SDG&E. In 2013, SCE's system average rate was 15.4¢/kWh PG&E's was 16.1¢/kWh, and SDG&E's was 17.7¢/kWh.[1]

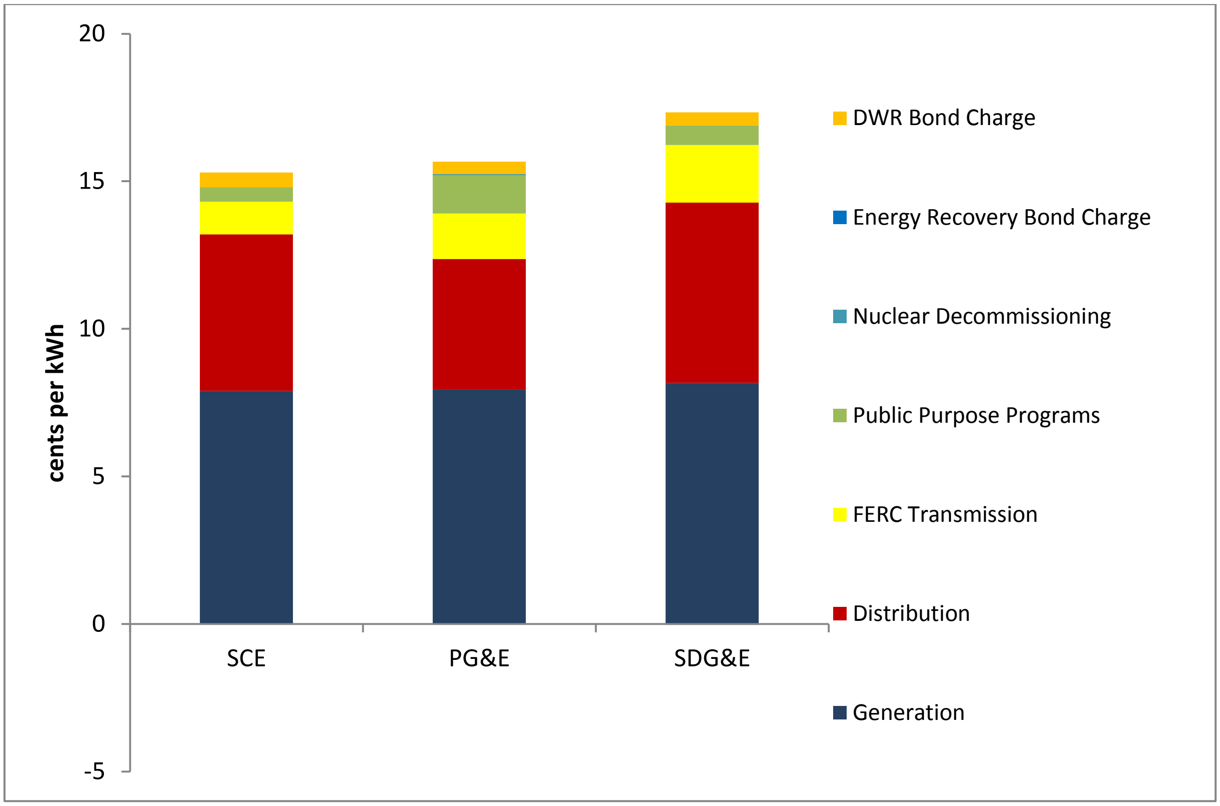
Figure 1.1: Trends in Average Rates



- **Electric generation and energy procurement are a large component of electric rates.** Generation, provided through utility owned generation and purchased power sources, collectively accounts for approximately 50% of the utilities' electric rates**.**

[1] See SCE Advice Letter 2971-E (effective 10/1/13); PG&E Advice Letter 4282-E-A (effective 10/1/13); and SDG&E Advice Letter 2513-E (effective 9/1/13).

Figure 1.2: 2013 Rate Components



- **Demand side management has been a cost effective method to meet new demand.**

  Demand response and energy efficiency programs provided bill savings from 2010 to 2012 with demonstrated cost effectiveness. Based upon reported IOU expenditures and benefits during this time period, energy efficiency gas and electric savings exceeded costs by nearly $3 billion (see Figure 3.6 below). In addition to energy efficiency and demand response, the CPUC has several distributed generation and integrated demand side management programs, including the California Solar Initiative (CSI) program and the Self-Generation Incentive Program (SGIP).

- **Renewable Portfolio Standard (RPS) eligible energy remains a small but growing component of the revenue requirements.** PG&E, SCE, and SDG&E collectively served 20% of their retail electricity load with renewable power in 2012. Since 2003, 6,240 MW of new renewable capacity has achieved commercial operation under the RPS program. Additional projects – over 1,000 MW – have come online since 2003 under short-term contracts, but the RPS program is not generally credited with incenting the development of these projects.

- The CPUC approved 112 contracts, representing 756 MW of renewable capacity in the first three quarters of 2013. Greater than 1,742 MW of renewable capacity came online in the first three quarters of 2013[2].

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Gas Utility Costs

- **Total natural gas utility costs in 2013 increased by 7.5% from last year,** primarily due to increases in CPUC authorized transportation and distribution costs.

- **Natural gas utility revenue requirements for transmission, distribution and storage services increased by 9.4% in 2013 from 2012, and by 23% from 2008.**

- **Costs authorized by the CPUC for natural gas public purpose programs have increased by 28% since 2008**, due to cost increases for energy efficiency programs, low income energy efficiency, and the CARE subsidy.

The remainder of this report provides a breakdown of the various electric and gas revenue requirement components and identifies those components that have experienced the greatest increase. 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 investor owned utility (IOU) revenue requirements organized by the rate components typically shown on customer bills. Appendix A revenue requirements include balancing account adjustments – the remainder of this report discusses 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 rate-setting 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) at the CPUC.
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 where 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 authorized here.
4. Specific program area proceedings where the program budget is determined.

The utilities earn a rate of return or profit only on costs that are capitalized (e.g. assets and equipment). For many cost categories, such as purchased power and fuel, there is no mark-up or profit – the utilities are only reimbursed for their costs. These are commonly referred to as pass-through costs.

Categorization of Utility Costs

Utility costs or revenue requirements fall into three major categories: generation, distribution, and transmission. This categorization not only reflects major areas of utility operations, but it is also used to determine what portion 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. These customers may generate their own power on site or buy power from a non-utility source (e.g., an electric service provider, or ESP, or a community choice aggregator). 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 large customers receive service at transmission voltage levels and are not charged for use of the utility distribution system.

Table 1.3: 2013 IOU Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Generation/Energy Procurement			
Purchased Power	$4,030,814	$3.708,540	$762,688
Utility Owned Generation	$1,808,238	$2,156,302	$517,245
Distribution	$4,003,579	$4,158,699	$1,137,547
Transmission	$1,429,364	$899,889	$412,807
Demand Side Management and Public Purpose Programs	$643,864	$607,641	$193,784
Bonds & Fees	$601,878	$474,830	$107,949
Total 2013 Revenue Requirement	**$12,517,739**	**$12,005,091**	**$3,132,021**

Rate Base

The rate base 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 on their rate base. Other things being equal, a larger rate base results in higher net income for the utilities (and vice versa).

Depreciation causes utility rate base for existing assets to decline over time, while building new plant or capital improvements to existing plant cause rate base to increase. Changes in rate base also result in changes in the depreciation allowance utilities are authorized to collect. As shown in Figure 1.5, the result of these competing effects has historically been a net increase in rate base. Between 2004 and 2013, the utilities' rate base increased from $23 billion to $46 billion, leading to increases in GRC revenue requirements.

Figure 1.4: 2013 Rate Base

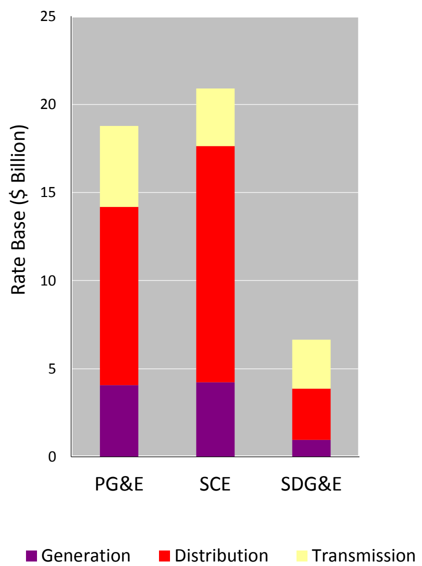
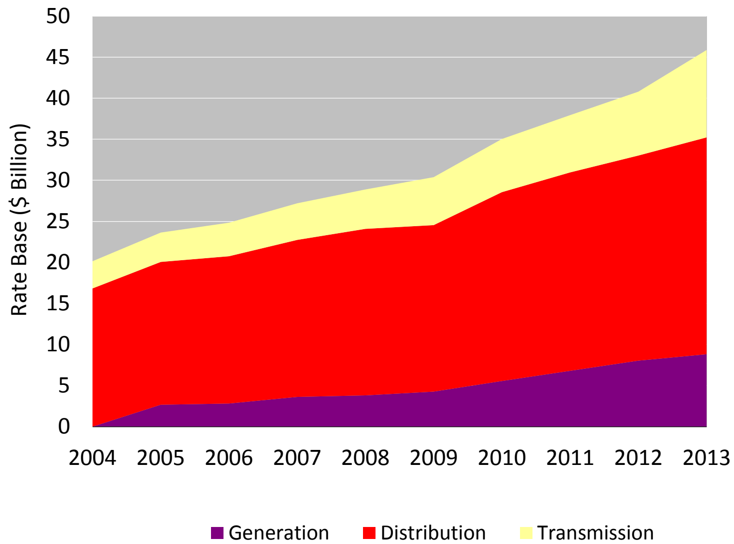


Figure 1.5: Trends in Rate Base



II. General Rate Case Revenue Requirements

Costs that utilities can forecast with reasonable accuracy are examined and approved by the Commission in GRC proceedings. These proceedings are usually on a three year cycle for the major utilities, although the interval may occasionally be longer than three years. In the GRC proceedings, the Commission sets a pre-specified revenue requirement for the first year, called the "test year," with formulaic adjustments for the following years (commonly called attrition years) until the next GRC decision takes effect.

The utilities' authorized revenue requirements typically remain the same even if the utilities spend more or less than adopted by the Commission. GRC ratemaking with pre-specified budgets is aimed at providing the utilities with an incentive to stay within approved budgets. Under this ratemaking treatment, utility profits decline if spending is higher than the GRC authorized revenue requirement, and vice versa.

Approximately 56% of the utilities' revenue requirements are set in general rate cases at the CPUC and FERC. The remaining 44% consists of pass-through costs determined to be reasonable by the CPUC. The transmission revenue requirement determined by FERC in transmission owner rate cases follows similar test year ratemaking treatment.

GRC revenue requirements are generally categorized as Distribution Revenue Requirements, Utility Owned Generation (UOG) Revenue Requirements, and Transmission Revenue Requirements. Each of these categories is comprised of the following major cost elements: operations and maintenance (O&M), depreciation, return on rate base and taxes. Table 2.1 below summarizes the total CPUC-jurisdictional GRC revenue requirements broken down into these cost categories for the three major electric utilities.

Table 2.1: 2013 General Rate Case Revenue Requirements[3] ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$2,105,667	$2,700,554	$784,102
Depreciation	$1,110,175	$1,533,795	$274,536
Return on Rate Base	$1,243,647	$1,386,569	$272,368
Taxes	$771,032	$777,243	$216,434
Total	**$5,230,522**	**$6,398,161**	**$1,547,440**

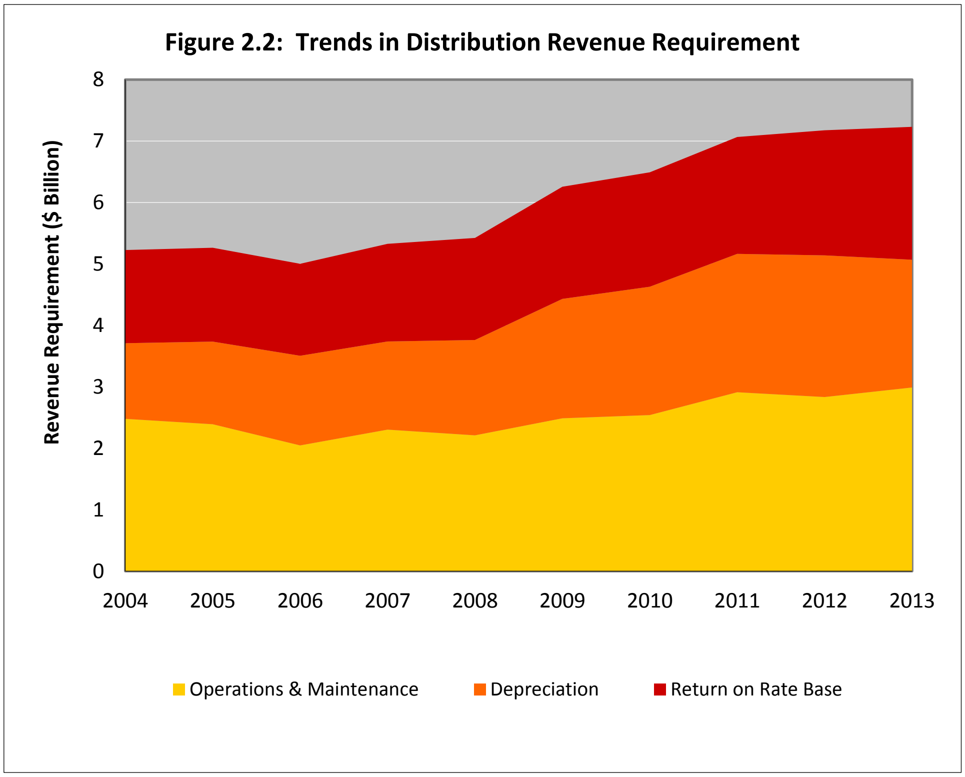
(Excludes FERC determined transmission revenue requirements)

- **O&M:** These costs include all labor and non-labor expenses for utility operation and maintenance of generation plants and the distribution system. The utilities are required to maintain their systems in accordance with the Commission's safety and reliability standards and industry best practices, but the Commission does not typically dictate how the utilities spend O&M funds. Depending on how the utilities manage various projects and prioritize their budgets, they may spend more or less than the Commission's authorized O&M budget. In the GRC proceedings, the Commission undertakes a thorough review of O&M separately for generation and distribution related facilities and for general plant.
- **Depreciation:** Capital investment in utility facilities and assets is financed by the utilities using their own funding sources. The capital used to finance these assets is returned over specified time periods in the form of a depreciation allowance. Depreciation spreads the ratepayers' cost of the physical electric plant and systems over its useful life.
- **Return on Rate Base:** Because the utilities provide the upfront financing for all capitalized expenditures, the Commission authorizes a rate of return on the invested capital. The rate of return is the weighted average cost of debt and shareholder equity. The Commission allows a fair and reasonable return sufficient to allow the utilities to obtain financing. The rate of return was formerly determined in each utility's GRC, but today the Commission conducts a separate cost of capital proceeding to determine the rate of return for the major energy utilities. The utilities' actual rate of return may be more or less than the rate of return authorized by the Commission, depending on how well the utilities manage their operations and costs (e.g. one-way balancing accounts for vegetation management). In most instances, if the utilities keep costs below their authorized revenues, actual rates of return will exceed authorized levels, and vice versa. There are some areas where if the utility underspends authorized funds, the remainder must be returned to ratepayers.

In addition to the authorized rate of return, the Commission has instituted some incentive programs such as the energy efficiency Risk/Reward Incentive Mechanism (RRIM) whereby the utilities share the savings or cost reductions with ratepayers. The utilities do not earn a return on purchased power and fuel expenditures, which, as noted previously, are pass-through costs reviewed in ERRA proceedings.

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

Distribution Revenue Requirements

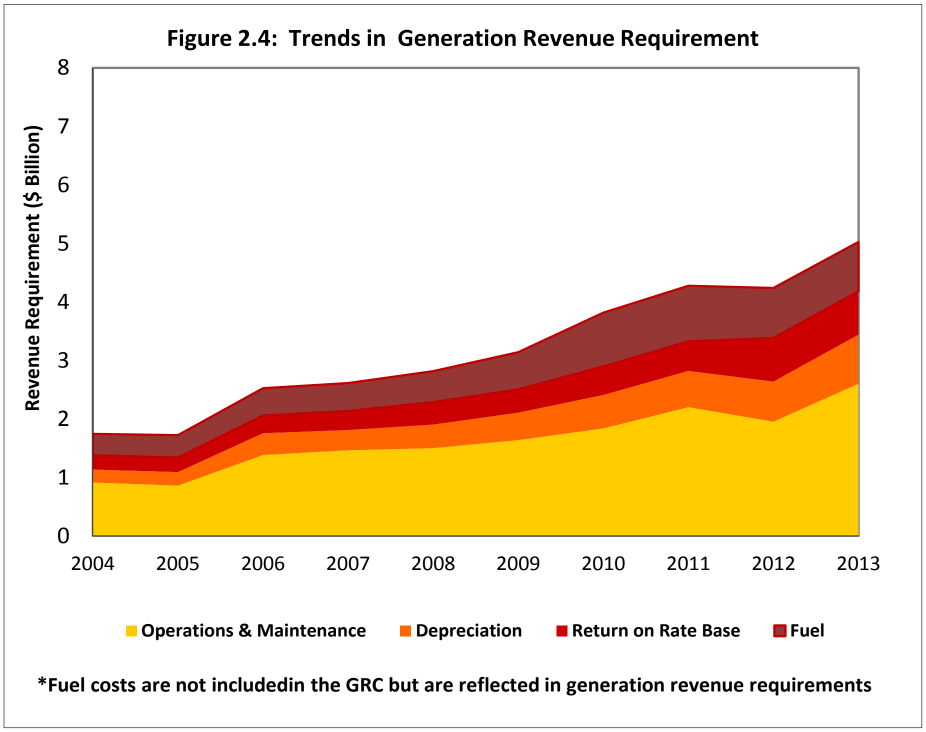


Since 2004, the total distribution revenue requirement, excluding franchise fees and taxes, has increased from $5.2 billion to $7.2 billion. Over the same time period, depreciation expenses have experienced the greatest increase, with a 6.0% average annual growth rate. O&M and return on rate base have increased annually by 2.1% and 4.0%, respectively. The increases in distribution costs are primarily due to capital additions and infrastructure improvements to the distribution system. These distribution infrastructure investments have increased rate base, as discussed on page 9.

Table 2.3: 2013 Distribution Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$1,164,096	$1,348,847	$477,272
Depreciation	$776,287	$1,076,350	$226,342
Return on Rate Base	$887,364	$1,056,719	$218,115
Total	**$2,827,747**	**$3,481,916**	**$921,729**

Utility Owned Generation Revenue Requirements



The revenue requirement for utility owned generation (UOG) includes O&M costs, depreciation and return on rate base related to these facilities. As older generating plants depreciate, costs of owning those plants decrease over time, even though costs of operating them may increase. As 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, depreciation, and return on ratebase tend to increase over time, as shown in Figure 2.4. The UOG revenue requirement increased recently due to nuclear steam generator replacements by SCE and PG&E and additions of new UOG peaking capacity. In 2006, some administrative and general expenses were re-categorized as generation expenses in the GRC. Because of this, O&M expenses for generation increased in 2006 and decreased for distribution.

While the majority of UOG revenue requirements are authorized in the GRC, fuel costs are authorized annually through ERRA proceedings because fuel prices fluctuate with the market. Following restructuring and divestiture of fossil-fueled generation, UOG (including fuel costs) now accounts for approximately 33% of the combined utility supply portfolio and approximately 15% of their combined revenue requirements.

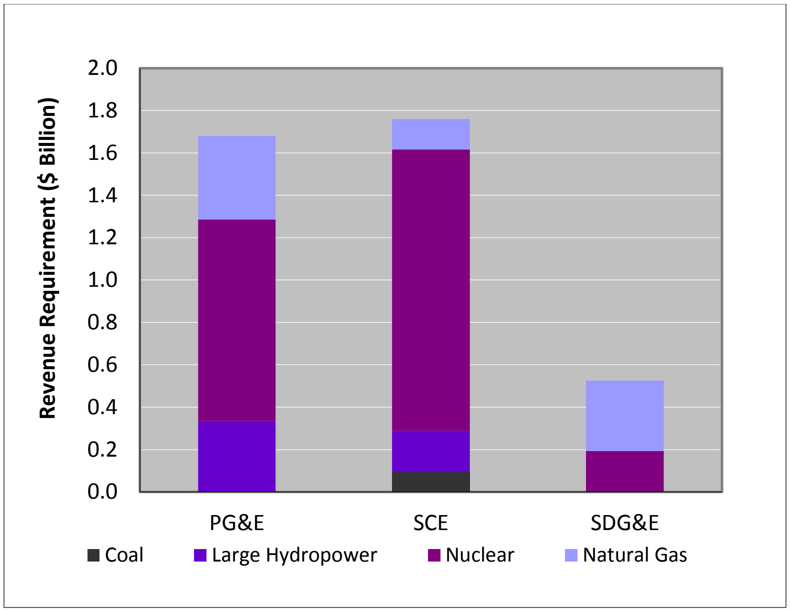
Table 2.5: 2013 Generation Revenue Requirements ($000)

	PG&E	SCE	SDG&E
Operations and Maintenance	$941,571	$1,351,707	$306,830
Depreciation	$333,889	$457,446	$48,194
Return on Rate Base	$356,283	$329,849	$54,253
Total	**$1,631,743**	**$2,139,002**	**$409,277**

PG&E's UOG consists primarily of hydro-electric, nuclear power (Diablo Canyon), and an increasing 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, coal (with a joint ownership stake in Four Corners Generating Facility in New Mexico), and natural gas power plants, including the 1,035 MW Mountain View Power Plant and peaker plants. SCE's reliance on coal has substantially decreased since the Mohave Generating Station was taken out of service.[4] SDG&E's UOG includes nuclear and 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.[5]

Figure 2.6: 2013 Revenue Requirements of UOG Sources



SCE and SDG&E also hold joint ownership in San Onofre Nuclear Generating Station (SONGS), and SCE holds partial ownership in Palo Verde Nuclear Generating Station in Arizona.[6] Due to operating issues at SONGS, this facility has been offline since the first quarter of 2012. In 2014, SCE and SDG&E were authorized by the CPUC to purchase replacement power to alleviate the capacity shortfall. Due to capital investment in new steam generators, nuclear generation revenue requirements have increased steadily, at an average annual increase of approximately 8% per year. Note that ratepayer responsibility to bear these costs is now pending in the SONGS OIR.

The utilities divested most of their natural gas generation capacity in 1998, but during the prior ten years have acquired a number of natural gas plants resulting in increases in UOG revenue requirements.

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[4] In addition, the Commission approved SCE's sale of its stake in the Four Corners plant in March 2012, but this transaction did not close in 2012.

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

[6] 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.

Besides the O&M, depreciation and return 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:[7]

- **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 lives.

Authorized Rate of Return

Figure 2.7: Trends in Weighted Average Rate of Return

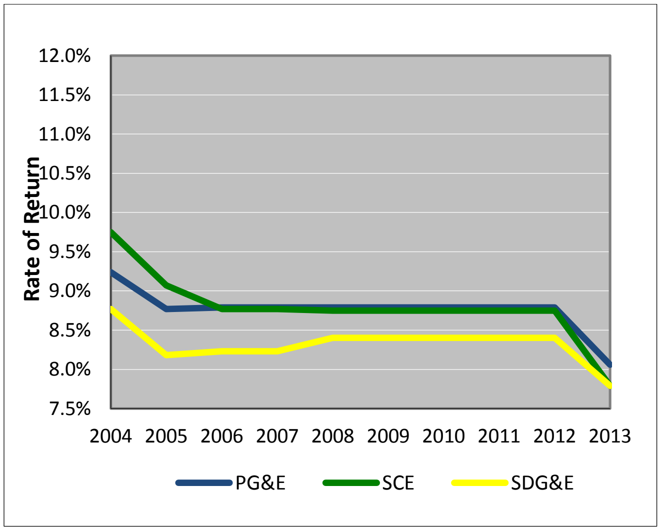


Figure 2.8: Trends in Return on Equity

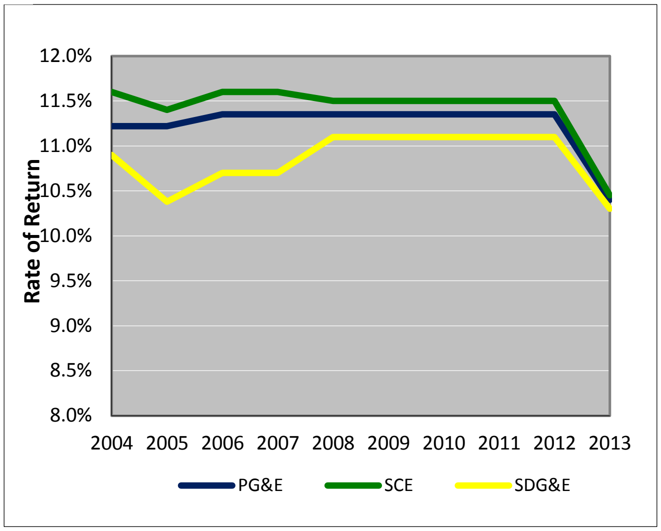


Figure 2.7 shows the weighted average rate of return (ROR) authorized by the Commission since 2003 for each utility. The ROR is the weighted average cost of debt and shareholder equity. This figure does not include the ROR authorized by the FERC for IOU transmission systems – it only includes return authorized by the CPUC for utility owned generation and distribution. The weighted average ROR for the SCE and SDG&E declined in 2004. For PG&E and SCE, the weighted average ROR, after falling to lower levels, remained stable between 2006 and 2012. For SDG&E, the ROR after falling to a lower level in 2005 gradually ascended. It became stable between 2008 and 2012. Figure 2.8 shows the trends in the return on equity (ROE) component of the ROR.

The utilities filed cost of capital applications in 2012 and resulted in D. 12-12-034, which lowered the authorized ROR and ROE. This decision affects the utilities' returns beginning in 2013. In D.13-03-015 the Commission approved a cost of capital mechanism for 2014 and 2015. The returns will not change in 2014 based on that mechanism.

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

Transmission Revenue Requirement

Background and Jurisdictional Separation History

As a consequence of the Energy Policy Act of 1992, unbundling of electrical services was mandated to grant regulatory oversight for the electricity transmission market to the Federal Energy Regulatory Commission (FERC) and create open access to the electric transmission grid across the nation[8]. The California Independent System Operator (CAISO) was created and given operational control[9] over the California utilities' high voltage transmission lines on January 1, 1998. The CPUC is the constitutionally designate 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.

Because each utility defines its high voltage transmission lines differently, transmission revenue requirements (the amount of money a utility collects from customers to pay for operating costs, capital costs, and a fair return on investment) vary significantly. 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 Rate Cases before the FERC, Achievements, 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[10]. To this end the CPUC actively participates in TO rate cases before the FERC to advocate for just and reasonable rates in federal wholesale electric market proceedings. Due to the importance and intricacies of these rate cases, CPUC legal staff and Energy Division regulatory analysts partner together to examine a multitude of cost of service and capitalization issues for adequacy, cost effectiveness, safety, and prudence.

The 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. The CPUC team, other joint interveners and FERC staff conduct discovery on the utilities filings to collect evidence and develop a fact-based ***fair and reasonable*** revenue requirement alternative recommendation to mitigate any negative impact on California ratepayers. The proceeding continues under a FERC settlement Administrative Law Judge where the parties negotiate a settlement or are order to proceed to go hearings if the settlement process does not result in a settlement of the rate case.

In 2013, most of the CPUC's electric FERC-related work consisted of TO rate cases for PG&E, SCE and SDG&E. As the result of the CPUC's persistence and expertise, the FERC has

[8] 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).

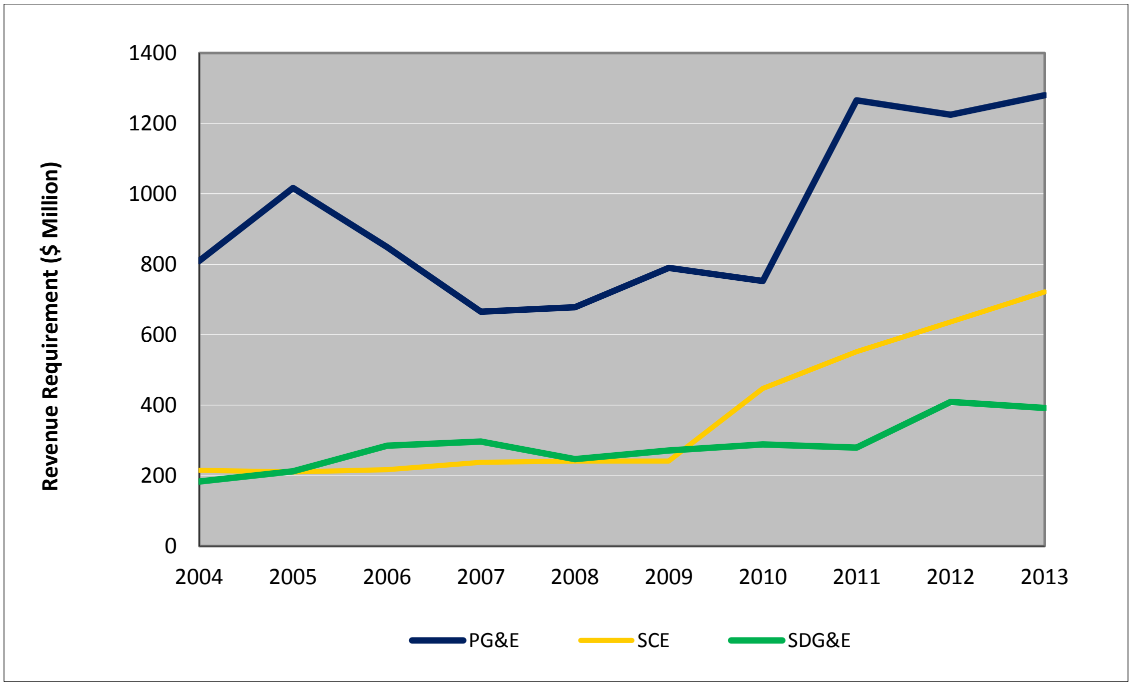
[9] The Restructuring Decision (1996) functionally created the implementation of the CAISO through the acceptance of AB1890 (Sept. 24, 1996).

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

ordered the reduction of $409 million[11] to the retail revenue requirements' filed by the IOUs. These savings are reflected in lower rate increases of electricity charges for California ratepayers.

Lastly, transmission revenue requirements for PG&E, SCE and SDG&E have been trending up since 2003 as a result of varied growth rates of the utilities expenditures. Much of the increase in the revenue requirements is due to the additional costs of transmission plant capital additions which have been built by the utilities. Over a ten-year period, due to CAISO reliability and RPS mandates, the average of yearly percentage changes in PG&E's transmission revenue requirement has increased at a 10.6% annual average rate, SCE's at a 17.3% annual average rate, and SDG&E's at a 9.9% annual average rate.

Figure 2.9: Trends in Transmission Revenue Requirements[12]



III. Power Procurement Costs

The generation revenue requirement includes the UOG revenue requirement discussed in Chapter II, as well as purchased energy and capacity costs. As previously noted, the utilities divested almost all of their fossil fueled generating plants during restructuring in the late 1990s

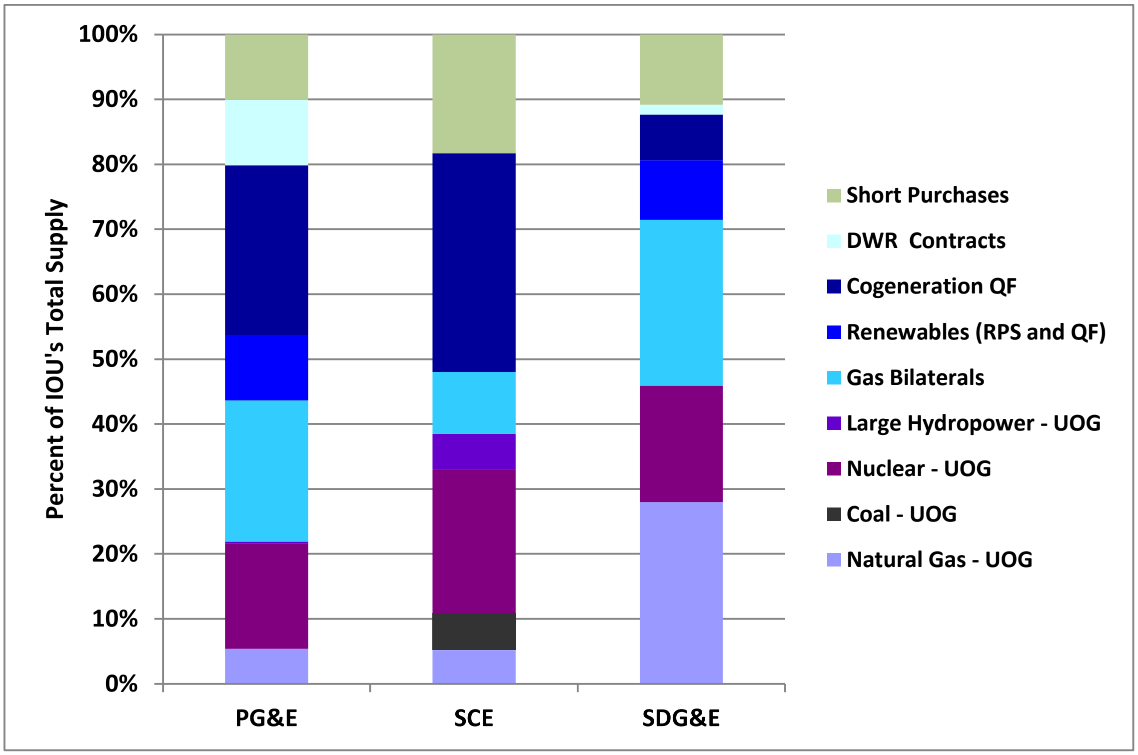
[11] Revenue requirement reductions for the PG&E TO14 case is $181 million, for the SCE TO7 case $111 million, and for the SDG&E TO4 case $117 million.

[12] Reliability Services was the largest contributor to the 2005 spike, which was due to intra-zonal congestion costs incurred in 2004. See CAISO 2005 Annual Report, April 2006, pp. 6-5 to 6-7. Retrieved from: http://www.caiso.com/17d5/17d59ec745320.pdf.

and had been relying primarily on purchased power for incremental electricity needs, although this has begun to change in recent years with the expiration of power contracts and the acquisition of new utility-owned natural gas plants.

In 2013, on a forecast basis, purchased power accounted for 68% of the total generation revenue requirement while the utility owned generation revenue requirement comprised about 32%. Power purchase costs represent the largest component of generation costs and accounted for 37% of total revenue requirements. Recovery of these costs is authorized through ERRA proceedings and not through GRCs, and there is no mark-up or profit for the utilities on purchased power expenses.

Figure 3.1: 2013 Forecast Energy Supply



Background

Heavy reliance on power purchases rather than utility owned power plants began with the enactment of AB 1890, 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 generation. The CPUC provided a rate of return 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 highly exposed to spiking 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 Commission 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 Commission required the IOUs to create.

AB 380 (2005) further addressed Commission responsibilities for resource planning, requiring the Commission, 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) and raised the RPS obligation to 33% by 2020.

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. It also established local market power mitigation in areas with constrained transmission capacity. 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 are 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 Commission 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 of these contracts, DWR's revenue requirement for PG&E and SCE was negative in 2013 and resulted in a refund of operating reserves to PG&E and SCE customers.[13] The majority of the contracts expired by the end of 2012. DWR costs have also decreased in recent years due to the declining price of gas. As discussed further below, there is also a DWR bond charge that is collected separately in electric rates.

[13] These refunds were supplemented as a result of the settlement on allocation of the Continental Forge Settlement Discount and the Sempra Long-Term Contract Refund, see D.12-05-006.

Qualifying Facilities (QFs)

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.[14]

Figures 3.2 and 3.3 break out QF supply and revenue requirements for cogeneration and renewable energy. The renewable energy supply meets the requirements for the Renewable Portfolio Standard. The total energy supply provided by all QFs, cogeneration and renewable, has decreased by about 15% since 2004 as older contracts expire, and the QF revenue requirement has decreased by approximately 18% since 2004.

Figure 3.2: Trends in Purchased Power Supply (GWh)

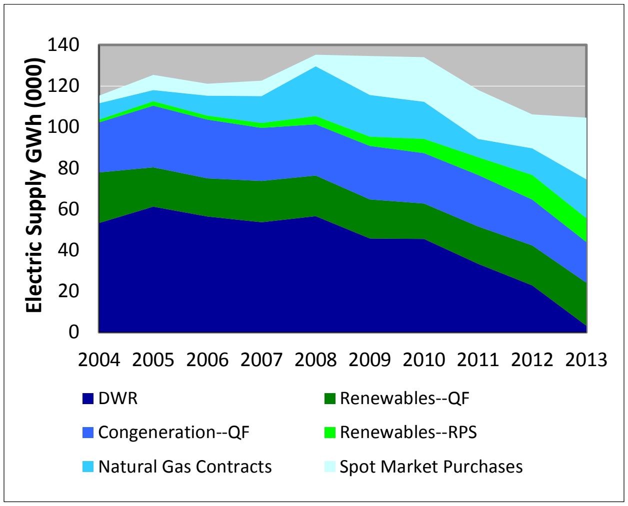
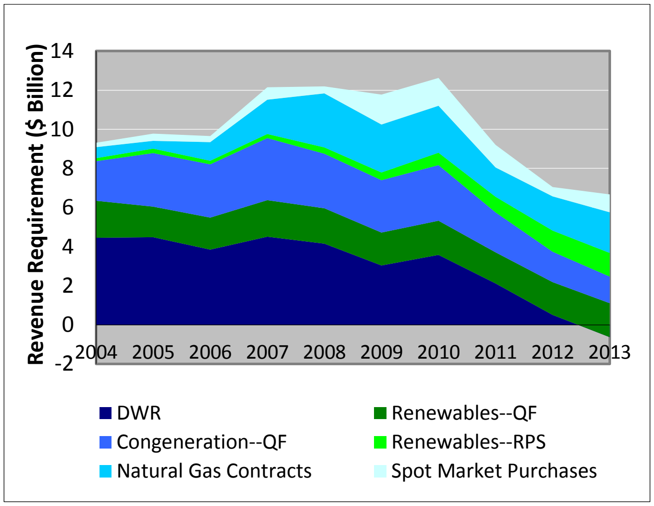


Figure 3.3: Trends in Purchased Power Revenue Requirements



Bilateral Contracts and Capacity Contracts

Bilateral contracts are the standard method for new energy procurement today. These contracts are entered into directly between the utility and an independent power supplier, which may be a generator or a trader. The utilities 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 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.

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

Bilateral contracts represent a larger portion of the utility power procurement portfolio as the utilities replace expiring DWR contracts. Because bilateral contracts include long-term contracts and capacity contracts, bilateral contracts can cost considerably more than spot market purchases or short-term contracts. In comparison, spot and short term purchases are frequently less expensive because the supplier has an existing resource and is willing to sell at less than full cost to minimize losses. With the lessons learned from the energy crisis, the Commission 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 Commission requires long term resource planning and resource adequacy. The higher 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 2004, the revenue requirements from bilateral contracts have increased over 21% annually, and the average cost (¢/kWh) for bilateral contracts has increased by 4.5%.[15]

There are a few factors that help to explain this trend. First, in 2004, Commission Decisions 04-10-035 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. The capacity 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, a significant amount of electric capacity is only needed for a few peak hours each year, as approximately 10 percent of electric demand occurs for less than 150 hours per year. Natural gas fueled generation is often the resource best able to 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 increases the need for peaking capacity to fill in when, due to weather, wind and solar resources produce less energy. Recently, the utilities have added new peaking capacity to meet overall capacity requirements. As a result, UOG and contracted natural gas-fired generation costs are higher than would otherwise be expected, given 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 2008, Governor Schwarzenegger expanded the RPS program by Executive Order, raising the renewables goal to 33% of the state's energy requirements by 2020. In 2011, SB 2 codified the 33% renewables target.

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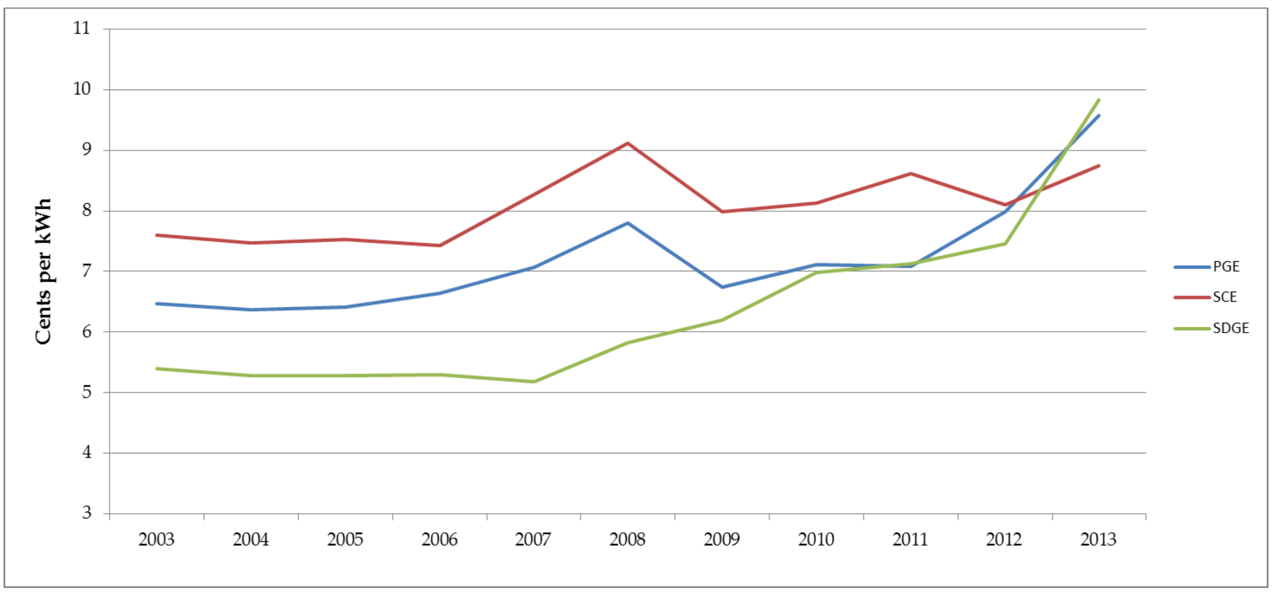
[15] Bilaterals represent natural gas contracts only.

The RPS mandate has made renewable energy central to the state's energy procurement planning. However, renewable energy revenue requirements remain a relatively minor component in the total revenue requirement at present, 12.2% in 2013.[16] Figure 3.4 illustrates the annual weighted average TOD-adjusted RPS procurement expenditure for renewable energy in dollars per kilowatt hours ($/kWh) for each of the investor-owned utilities (IOUs): Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E).

The key factor driving the cost differences between the utilities is the resource mix of RPS-eligible resources within an IOU's portfolio. It is important to note that the resource mix will change over time as renewable prices and IOUs' RPS portfolios change over time. The increase in procurement expenditures for 2013 is attributed to 44 additional projects, with an average price of 13.8 cents per kWh, achieving commercial operation. These 44 projects accounted for approximately 3.5% of the total bundled RPS generation in 2013. The contracts for the projects that came online in 2013 where largely executed between 2008 and 2010. Contracts that have been executed and approved during 2012 and 2013 have much lower prices, and Energy Division staff expect the average cost of RPS eligible procurement to decrease in the near future.

Figure 3.4: Weighted Average TOD-Adjusted RPS Procurement Expenditures of Bundled Renewable Energy by Year (2003 – 2013)



From 2003 to 2013, the average TOD-adjusted price of contracts approved by the CPUC has increased from 5.4 cents to 8.4 cents/kWh in nominal dollars, or 8.0 cents to 8.4 cents/kWh in real dollars. [17] One reason for this increase is that the IOUs contracted with existing renewable facilities at the beginning of the RPS program and with mostly new facilities in more recent

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

[17] The CPUC used the Handy- Whitman Index of Public Utility Construction Costs – Transmission Production Plant - Pacific region –bulletin #176 - to calculate the real dollar amounts for year 2013.

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. For additional information on RPS contract pricing and renewable expenditures please see the 2014 Padilla and Public Utilities Code Section 910 report.[18]

Other Power Purchases

There are additional power purchase mechanisms to ensure that the utilities have secured sufficient capacity to balance load across the grid and meet peak load requirements. These include both sales and purchases.

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.

Other Factors Affecting Generation Costs

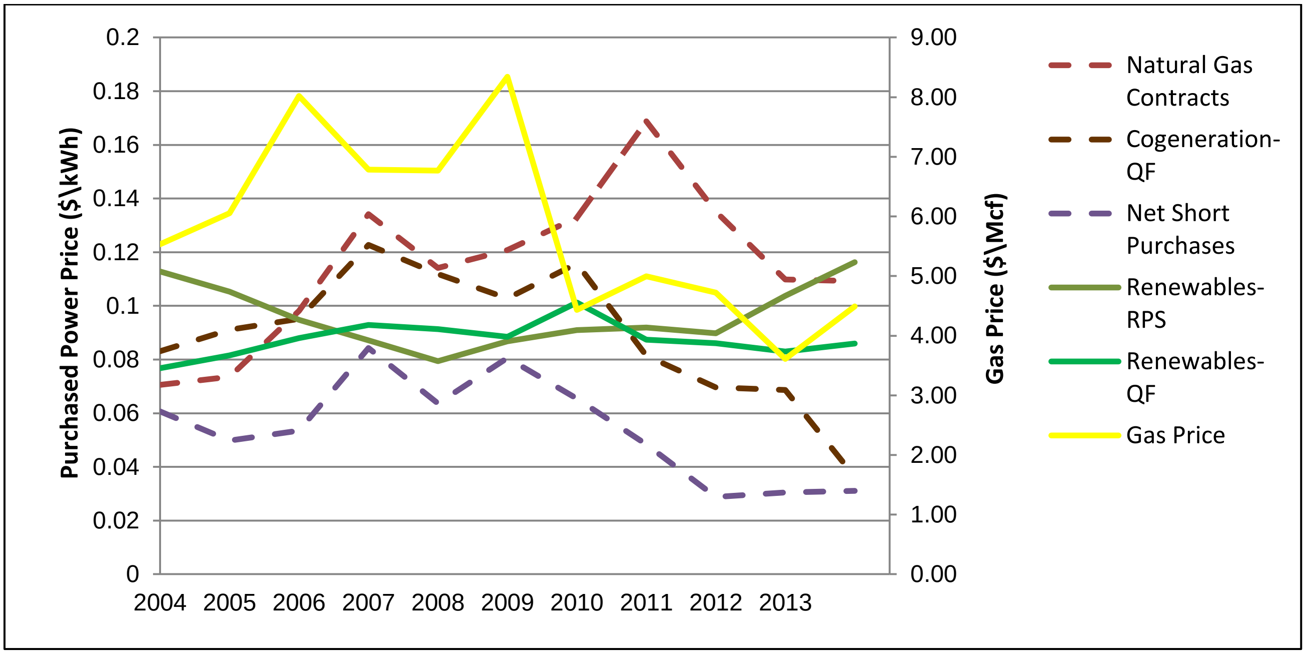
Prior sections have described many factors that cause energy generation and procurement costs to vary significantly between different types of procurement, and over time. Figure 3.5 shows the average costs of various types of purchased power. Evident in this figure is the significant effect one factor 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, n
- **N**atural gas bilateral contracts, cogeneration QFs, and spot market purchase power costs fluctuate and track with gas prices, which fell precipitously in 2008. Gas prices spiked after Hurricane Katrina in 2005 (red line), and has shown considerable fluctuation since

[18] Available at:

that time, as shown in Figure 3.5. Renewables contracts generally exhibit more cost stability because they are not pegged to the gas price.

Figure 3.5: Average Cost for Select Purchased Power[19]



IV. Demand Side Management & Customer Programs

Demand Side Management 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-generate through distributed generation. In 2003, the CPUC and the CEC adopted the Energy Action Plan to establish goals for the state's energy strategy.[20] 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 demand side management primarily consist of financial incentives to encourage demand side management activities, and the administrative costs to manage these programs. In order to achieve the goals established in the Energy Action Plan, spending on demand side management has experienced a 14% average annual increase since 2004, as 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 greater than the financial savings from reducing the demand for generation. In total, demand side management programs combined accounted for 4.9% of the total revenue requirement, however the revenue requirement does not incorporate the energy

[19] 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.
[20] The Energy Action Plan was updated in 2005 and 2008.

savings. In 2011, energy efficiency programs alone resulted in over $300 million in utility-reported net savings to ratepayers.[21]

In addition to demand side management, California also mandates customer programs to provide rate discounts and energy efficiency improvements for low-income customers.

Table 4.1: 2013 Demand Side Management and Customer Program Costs ($000)[22]

	PG&E	SCE	SDG&E	Total
Energy Efficiency	$290,164	$341,539	$89,271	$720,974
Demand Response	$79,240	$78,059	$0	$157,300
California Solar Initiative	$85,917	$74,832	$0	$160,749
Self Generation Incentive Program	$30,566	$28,315	$10,035	$68,916
Low Income Energy Efficiency	$92,139	$72,640	$12,304	$177,083
Total	**$578,027**	**$595,385**	**$111,610**	**$1,285,021**

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 Commission translated this policy into specific annual and cumulative numerical goals for electricity and natural gas savings by utility service territory. These goals are updated periodically by the Commission as required by PUC 454.55 and 454.56. The Commission-adopted energy savings goals are expressed in terms of annual and cumulative gigawatt hours (GWh), million-therms (MMtherms) and peak megawatt (MW) load reductions.

Prior to 2006, energy efficiency programs had largely been funded by the Public Goods Charge (PGC) as authorized by Public Utilities (PU) Code Sections 381 and 399. Currently, much of the energy efficiency budget is funded through the public purpose program component of rates and provides savings though avoided generation costs. The aggregated annual budget for energy efficiency programs increased from $283 million in 2003 to $846 million in 2013.

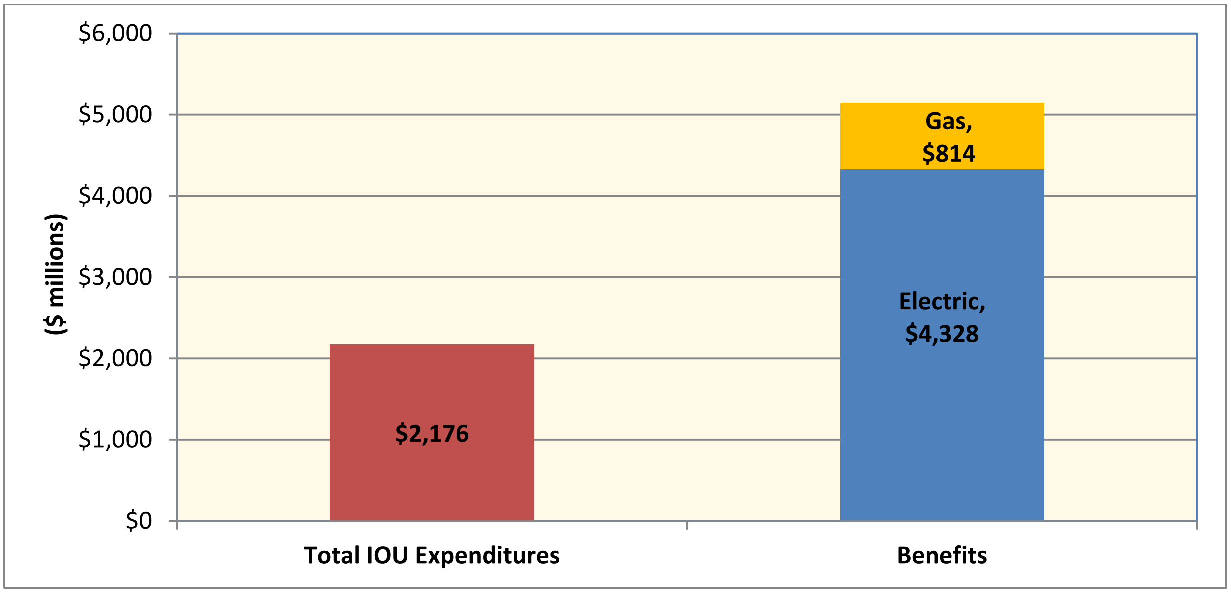
The Commission's 2006-2009 energy efficiency funding supported programs and activities that generated annual energy savings of 9,812 GWh, 1,717 MW and 112 MMtherms for ratepayers.[23] The net benefits over the life of these installed technologies and actions were estimated at $2.8 billion for the 2006-2008 period and an additional $1.5 billion in 2009[24]. The estimated cost effectiveness (Total Resource Cost – TRC) ratios were 1.14 and 1.54 respectively for those time periods.[25] The Commission has continued to support investments in energy efficiency across all market sectors in the state. The 2010-2012 energy efficiency

[21] Net savings based on 2011 utility reported energy efficiency savings and costs.
[22] Based upon the forecasted 2013 program costs
[23] 2006-2008 Energy Efficiency Evaluation Report - Executive Summary, p. ii; and Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period Executive Summary, p. 4.
[24] Net benefits were calculated by subtracting
[25] Ibid: 2006-2008, p viii; 2009, p. 4.

portfolio of programs was funded at $3.1 billion, and as of December 2012, claimed savings of 9,367 GWh, 1,710 MW, and 113 MMtherms (pending verification and evaluation expected to be complete in May 2014).[26] Like former programs, these 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 Commission has also supported programmatic activities targeted at the long term transformation of consumer energy markets through marketing, education, outreach, training and other program support.

Figure 4.2: Expenditures and Benefits from 2010-2012 EE Program Cycle ($ in millions)[27]



Demand Response

Demand response 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. Demand response saves 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. Demand response goals are met through customer programs and metering infrastructure upgrades.

- **Demand Response Customer Programs:** These programs are primarily aimed at large commercial and industrial customers that can shed load as an immediate or day ahead response. Customers are provided bill credits or payments to participate in the programs, and customers are called to curtail load on designated peak days. Demand

[26] Current Program Cycle Reported Savings Information (2010-12) at http://eega.cpuc.ca.gov/Default.aspx.
[27] IOU reported values were not evaluated by Energy Division. Data does not include Energy Savings Assistance Program savings and costs.

response programs can meet the needs for system reliability or peak capacity management.

- **Advanced Metering Infrastructure (AMI):** The AMI initiative is a statewide effort to upgrade all customers to an electronically integrated network, which enables greater communication and control system technologies to manage energy use. The benefits of AMI are threefold. First, AMI provides price and usage information that helps customers make better informed decisions about energy use, so they can optimize electricity consumption and reduce their bills. Second, AMI lowers the utilities' operating costs by reducing the need for manual meter reading. Third, it allows for faster outage detection and restoration of service by a utility when an outage occurs, resulting in less disruption to customers' homes and businesses. AMI costs are included with the distribution revenue requirements discussed on page 11.[28]

Distributed Generation

Ratepayers fund two distributed generation programs that provide financial incentives to participating customers – CSI and SGIP.

- **California Solar Initiative (CSI):** Established in 2006, CSI provides both up-front payments as well as payments stretched out over the projects' first five years, based on performance, for the installation of photovoltaic solar systems for residential and commercial customers up to 1 MW. The CSI Program has a budget of $2.367 billion over 10 years, and the goal is to reach 1,940 MW of installed solar capacity. The program will accept new reservations until the end of 2016, or until the incentive budget is spent, whichever occurs first. In SDG&E service territory, the CSI program is being implemented by the California Center for Sustainable Energy. The program in PG&E territory is no longer accepting reservations, as the budget there has been exhausted.

- **Self-Generation Incentive Program (SGIP):** Established in 2001, SGIP provides incentives to support distributed energy resources that will result in greenhouse gas emission reductions. The program is authorized through 2015. 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 advanced energy storage systems.

A benefit/cost study on the CSI program was issued in April 2011.[29] The CSI study forecasts that PV systems installed under the CSI program through 2012 will result in annualized life-cycle net costs to ratepayers of $150 million or more. From the ratepayer perspective, the excess of the participant's retail rate over the utility's avoided cost is the key driver of CSI program cost. Once the program ends, costs to ratepayers from net energy metering (NEM) will

[28] The authorized revenue requirements for AMI were $176.8 million for PG&E and $187.8 million for SCE in 2012.
[29] See ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/csi/CSI%20Report_Complete_E3_Final.pdf.

continue. The passage of AB 327 (Perea) in October 2013 opens the door to modifications to residential rates - including the possibility of minimum, or fixed, monthly charges - as well as the development of a new tariff or program to replace NEM, to be determined by the CPUC. As part of the redesign of the NEM program, the CPUC will determine the appropriate transition period for customer generators to remain on the existing NEM tariff by March 2014. The CPUC released an updated NEM cost-benefit study in October 2013, which found that NEM cost shift to non-NEM ratepayers is approximately $ 1 billion per year in 2020.

A cost-benefits study of SGIP was issued in February 2011.[30] The SGIP study concluded that most of the evaluated DG technologies are cost-effective. An updated Annual SGIP Impact Evaluation was also released in February 2014.

Low-Income Programs

IOUs provide two ratepayer-funded programs for low-income customers: CARE rate discounts and the Energy Savings Assistance Program which installs energy-efficient equipment in income-qualified homes.

Table 4.3: 2013 Low Income Program Costs ($000)

	PG&E	SCE	SDG&E	Total
CARE Subsidy	$762,698	$309,552	$45,225	$1,117,475
CARE Administrative Expenses	$11,804	$12,256	$4,274	$28,334
Low Income Energy Efficiency	$92,139	$72,640	$12,304	$177,083
Total	**$866,641**	**$394,448**	**$61,803**	**$1,322,892**

California Alternate Rates for Energy (CARE): The CARE program provides rate discounts for qualifying low-income customers. The minimum CARE rate discount was increased from 15% to 20% by Commission Decision 01-06-010 in 2001. In addition, during the energy crisis, AB 1X exempted CARE customers from certain DWR power costs and kept Tier 1 and Tier 2 residential rates frozen at pre-restructuring levels. Additionally, CARE customers do not have Tier 4 and Tier 5 rates for high consumption levels as non-CARE customers do. As a result, the effective CARE discount increased substantially above 20% for CARE customers with usage above Tier 1 and Tier 2.

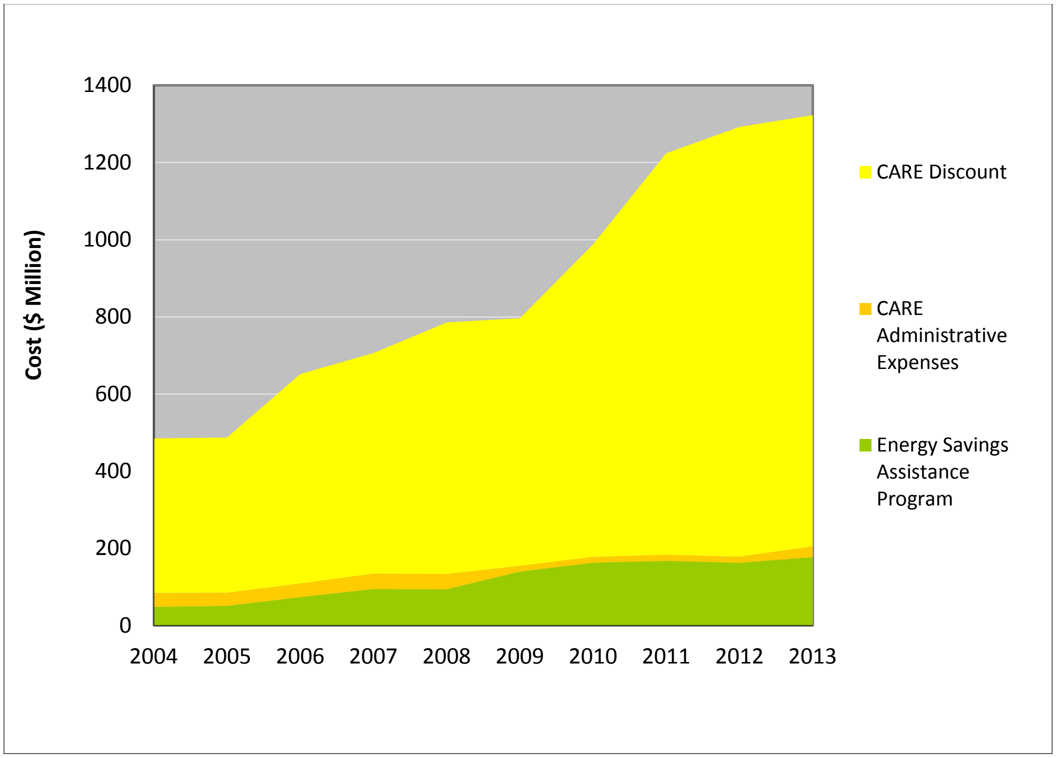
CARE costs have two components—CARE program administration cost and the cost of the discount itself. CARE program administration costs total approximately $16 million per year. The CARE discount is a much larger amount and is paid by non-CARE customers. A higher CARE discount does not result in a higher revenue requirement for the utility, but it does increase the rates that non-CARE customers pay. The cost of the PG&E CARE discount in 2013 was $763 million, compared to $310 million for SCE and $45 million for SDG&E. A

[30] See http://www.cpuc.ca.gov/NR/rdonlyres/2EB97E1C-348C-4CC4-A3A5-D417B4DDD58F/0/SGIP_CE_Report_Final.pdf

major reason is that PG&E's CARE Tier 3[31] rate was administratively set at 13.9 cents per kWh in 2013, whereas SCE's Tier 3 rate was 20.5 cents per kWh[32] and SDG&E's Tier 3 rate was 16.4 cents per kWh in the winter and 17.5 cents per kWh in the summer. The cost of the CARE discount has increased 15% annually since 2003.

Energy Savings Assistance Program (ESAP):[33] The ESAP is mandated by Public Utilities Code 2790, which requires gas and electric corporations to perform home weatherization services for low-income households, and defines those services to include the installation of HVAC measures, lighting measures, water heating conservation measures, and infiltration measures which include caulking and weather stripping. Weatherization services may also include other building conservation measures, energy-efficient appliances and energy education programs. ESAP is considered a low-income program for policymaking purposes, because the program's purpose is to improve the welfare of California's low-income population, by subsidizing and managing energy efficiency improvements for low income residences. In 2013, the ESAP program accounted for 0.9% of the IOUs' total revenue requirement.

Figure 4.4: Trends in Low Income Program Costs

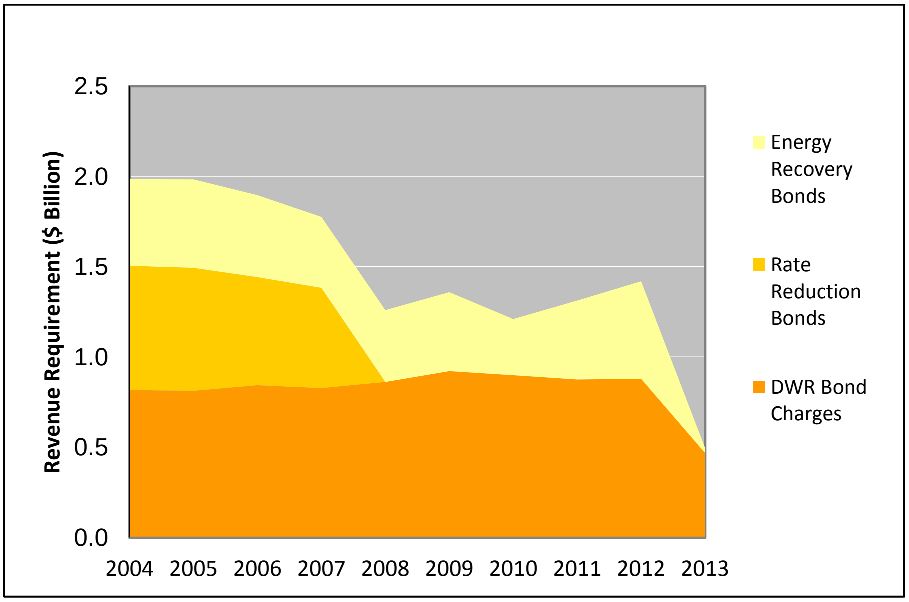


[31] PG&E implemented a Tier 3 CARE rate on November 1, 2011 in accordance with SB 695 (October 2009) and D.11-05-047.
[32] SCE AL-2964-E
[33] Formerly known as the Low Income Energy Efficiency (LIEE) Program.

V. Bonds and Regulatory Fees

The $1.4 billion revenue requirement for bonds constitutes the ongoing costs to ratepayers for the 2000-01 energy crisis. During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize the costs of energy restructuring and the energy crisis. Since the energy crisis, these bond costs have decreased from a peak of $2 billion in 2004 to $0.5 billion in 2013.

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 their June 1996 levels, and reduced rates for residential and small commercial customers by 10%.

DWR Bonds were issued in 2003 to recover the costs incurred by the State of California to purchase power during the energy crisis. A $7.2 billion balance remains outstanding on the DWR bonds[34] and 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 $2.7 billion as a Regulatory Asset. The Energy Recovery Bonds were issued by PG&E in 2003 to reduce the financing cost of the Regulatory Asset to ratepayers. But for the bonds, the Regulatory Asset would be financed at

[34] Department of Water Resources Electric Power Fund Financial Statements, December 31, 2012, p. 13, available at http://wwwcers.water.ca.gov/pdf_files/021513_epf_corrected.pdf.

PG&E's weighted cost of capital which was higher than the cost of these bonds. The Energy Recovery Bonds are scheduled to be repaid by the end of 2012.

Table 5.2: 2013 Bond Expenses ($000)

	PG&E	SCE	SDG&E	Total
DWR Bond Charges	$375,789	$374,944	$92,518	$843,251
Rate Reduction Bonds	$0	$0	$0	$0
Energy Recovery Bonds	$27,600	$0	$0	$27,600
Total	**$403,389**	**$374,944**	**$92,518**	**$870,851**

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 1% of the 2012 revenue requirement.

Table 5.3: 2013 Regulatory Fees ($000)

	PG&E	SCE	SDG&E	Total
Fees				
CPUC fee*	$20,557	$20,460	$0	$41,017
Catastrophic Events Memorandum Acct.	$106,304	$0	$0	$106,304
Franchise Fees & Uncollectible Surcharge**	$0	$0	$1,363	$1,363
Environmental Enhancement	$10,108	$11,885	$0	$21,993
Electricity Program Investment Charge (EPIC)	$0	$32,502	$0	$32,502
Nuclear Decommissioning	$44,270	$22,727	$8,070	$75,067
Spent Nuclear Fuel	$0	$6,443	$1,030	$7,473
DOE D&D Fees	$0	$0	$0	$0
Nuclear Decommissioning FF&U	$0	$328	$111	$439
Incentives				
Customer Service & Safety Performance Indicator Awards	$17,250	$0	$0	$17,250
Total	**$198,489**	**$94,345**	**$10,656**	**$303,409**

* 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.
** PG&E and SCE also collect these fees and charges, but they are not reported separately.

Definition of Fees

- **CPUC Fee:** This is the annual fee to recover the CPUC's operating costs.
- **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 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.
- **Hazardous Substance Mechanism (HSM)**: An account that provides a mechanism for allocating historical hazardous waste costs (such as from old-time coal to gas plants) among shareholders and ratepayers, including the allocation of insurance recoveries, if any.

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: 2013 Gas Revenue Requirement Summary by Key Components ($000)

	PG&E	SoCalGas	SDG&E	Total
Core Procurement	$1,359,218	$1,385,335	$188,067	$2,932,620
Transportation	$1,828,380	$2,218,229	$324,022	$4,370,631
Public Purpose Programs	$206,563	$319,252	$25,466	$551,281
Totals	**$3,394,161**	**$3,922,816**	**$537,555**	**$7,854,532**

For 2013, total natural gas utility costs increased by 7.5% from 2012 costs. This increase was due to increased gas procurement costs as well as CPUC authorized increases in transportation and distribution costs. The increase in procurement costs can be primarily attributed to gas prices which increased by around 30% compared to 2012. Still, natural gas procurement costs are much lower than in 2008. As the tables below show, gas utility transportation costs have moderately increased over the last six years, with the largest increase of the period occurring between 2012 and 2013. Natural gas public purpose program costs have steadily increased since 2008, but fell by 11% from 2012 to 2013.

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

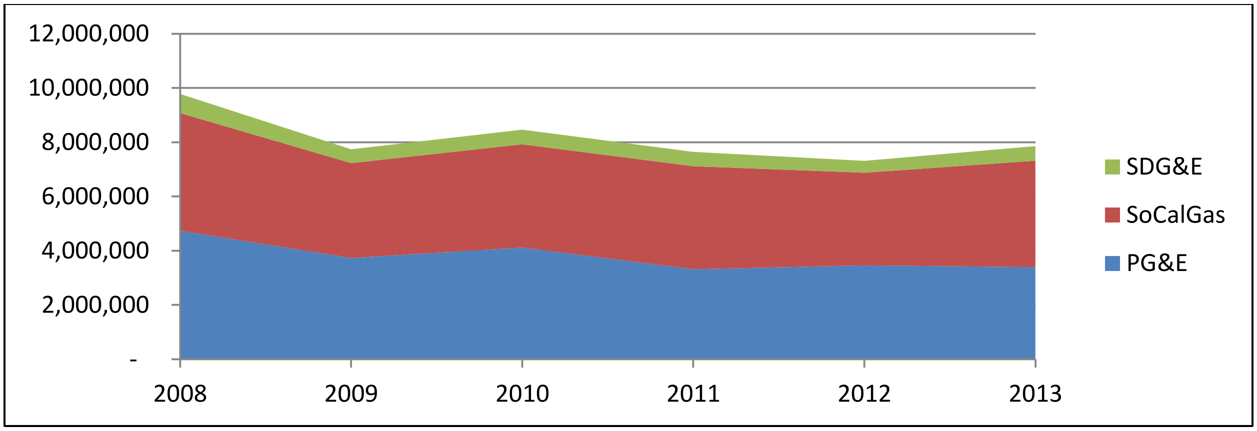


Figure 6.3: Trends in Gas Utility Revenue Requirement Components ($000)

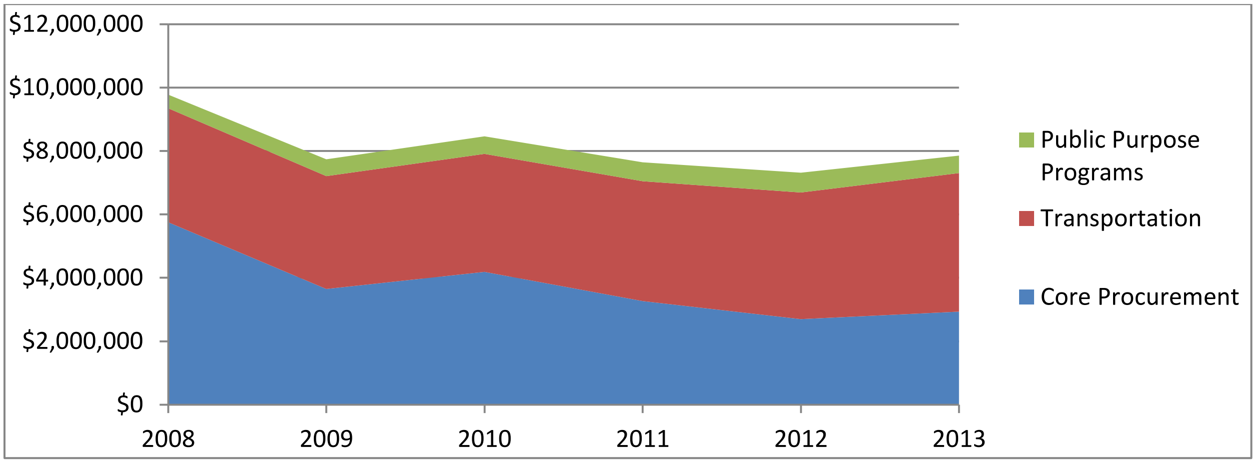


Table 6.4: Historic Gas Utility Revenue Requirement Summary ($000)

	2008	2009	2010	2011	2012	2013
Core Procurement	$5,753,175	$3,647,509	$4,186,881	$3,265,766	$2,696,629	$2,932,620
Transportation	$3,595,241	$3,559,641	$3,722,046	$3,781,343	$3,994,102	$4,370,631
Public Purpose Programs	$429,897	$531,482	$553,460	$596,016	$624,657	$551,281
Total	**$9,778,313**	**$7,738,632**	**$8,462,387**	**$7,643,125**	**$7,312,388**	**$7,854,532**

Table 6.5: Percent Change in Gas Utility Revenue Requirements Since 2008

	Core Procurement	Transportation	Public Purpose Programs
PG&E	-55.03%	20.93%	21.60%
SoCalGas	-40.56%	24.97%	37.35%
SDG&E	-52.99%	16.86%	-7.70%

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 2013 increased by 8.8% from 2012. Overall, natural gas core procurement costs have decreased by 49% since 2008. In 2013, core gas procurement costs accounted for about 37% 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.

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. As the following table shows, although natural gas utility procurement costs increased slightly in 2013, they were still significantly lower than in 2008.

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)

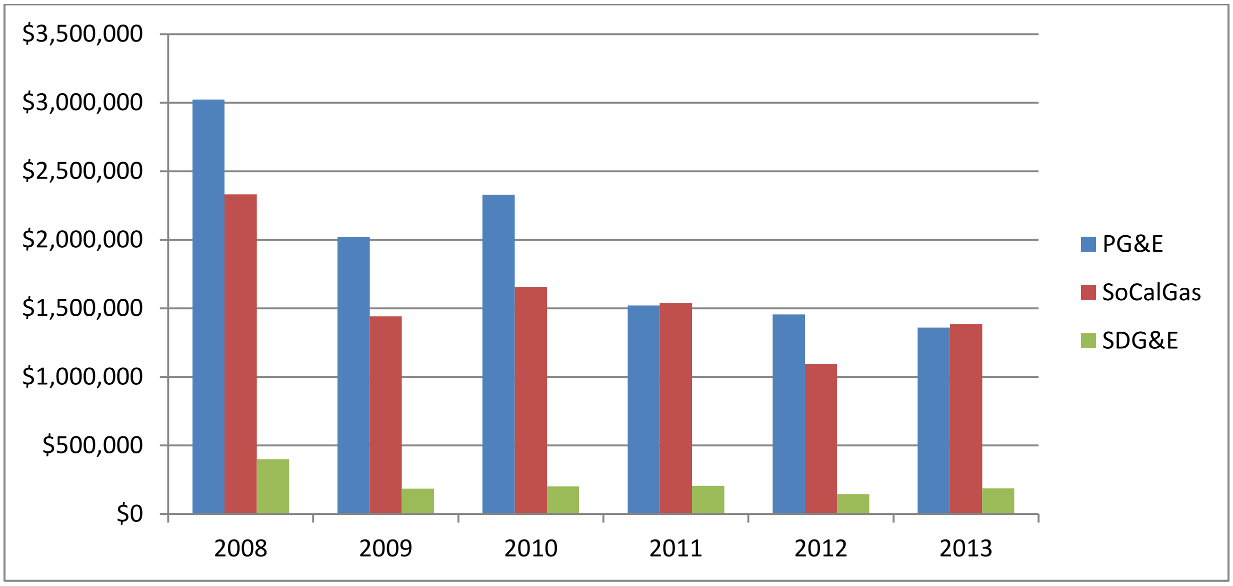


Table 6.7: Historical Revenue Requirement for Core Procurement ($000)

	2008	2009	2010	2011	2012	2013
PG&E	$3,022,339	$2,020,976	$2,327,868	$1,520,282	$1,455,016	$1,359,218
SoCalGas	$2,330,774	$1,441,099	$1,656,802	$1,538,869	$1,095,871	$1,385,335
SDG&E	$400,062	$185,434	$202,211	$206,615	$145,742	$188,067
Total	**$5,753,175**	**$3,647,509**	**$4,186,881**	**$3,265,766**	**$2,696,629**	**$2,932,620**

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 moderately increased in recent years. In 2013, gas transportation costs increased by 9.4% and represented about 56% 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 total authorized revenue requirements for transmission, distribution, storage, and customer services, combined under the "transportation" category, have been fairly steady in recent years, increasing by 11% from 2008 through 2012. However, this year's jump increases that figure to a 22.5% increase since 2008. Much of the increase can be attributed to the approval of increased revenue requirement in SoCalGas and SDG&E's last general rate case and for PG&E's gas transmission safety work.

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

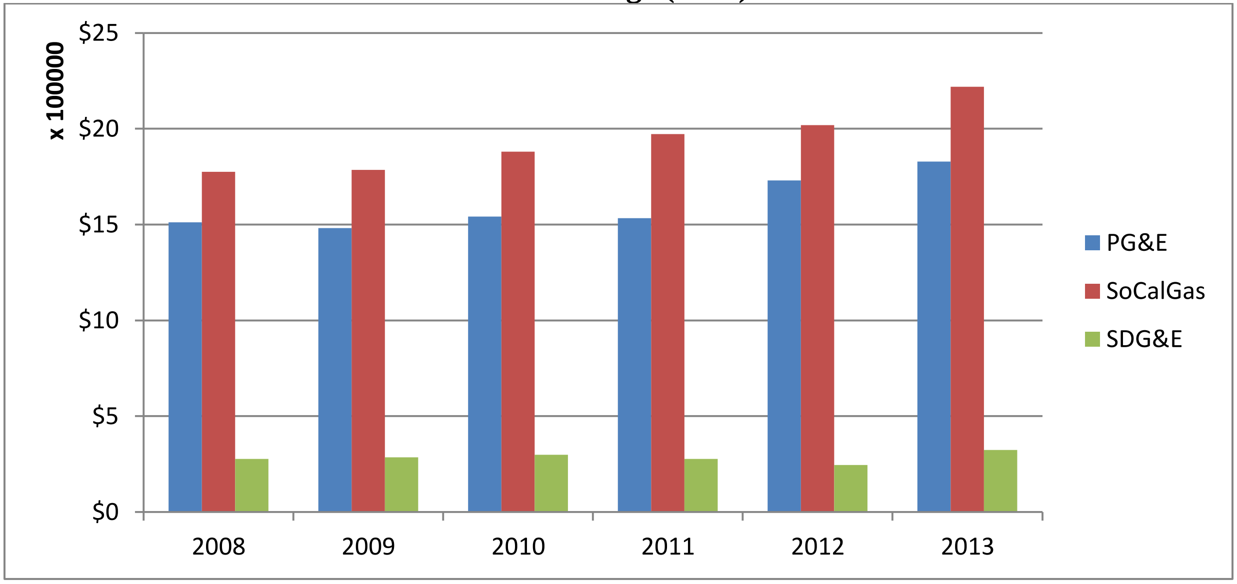


Table 6.9: Historic Revenue Requirements for Transportation Summary ($000)

	2008	2009	2010	2011	2012	2013
PG&E	$1,511,881	$1,482,381	$1,541,446	$1,533,332	$1,731,021	$1,828,380
SoCalGas	$1,774,960	$1,785,220	$1,880,826	$1,971,438	$2,018,108	$2,218,229
SDG&E	$277,271	$285,920	$299,774	$276,573	$244,973	$324,022
Total	**$3,564,112**	**$3,553,521**	**$3,722,046**	**$3,781,343**	**$3,994,102**	**$4,370,631**

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.

Though costs authorized by the CPUC for natural gas, PPPs have increased by 28% since 2008, they fell by 11% between 2012 and 2013. This was due primarily to PG&E's application of surplus CARE funding from previous years to their 2013 revenue requirement, as well as Commission approved reductions in energy efficiency goals for both SDG&E and PG&E. Gas PPP costs made up 9% of total utility costs in 2013.

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)

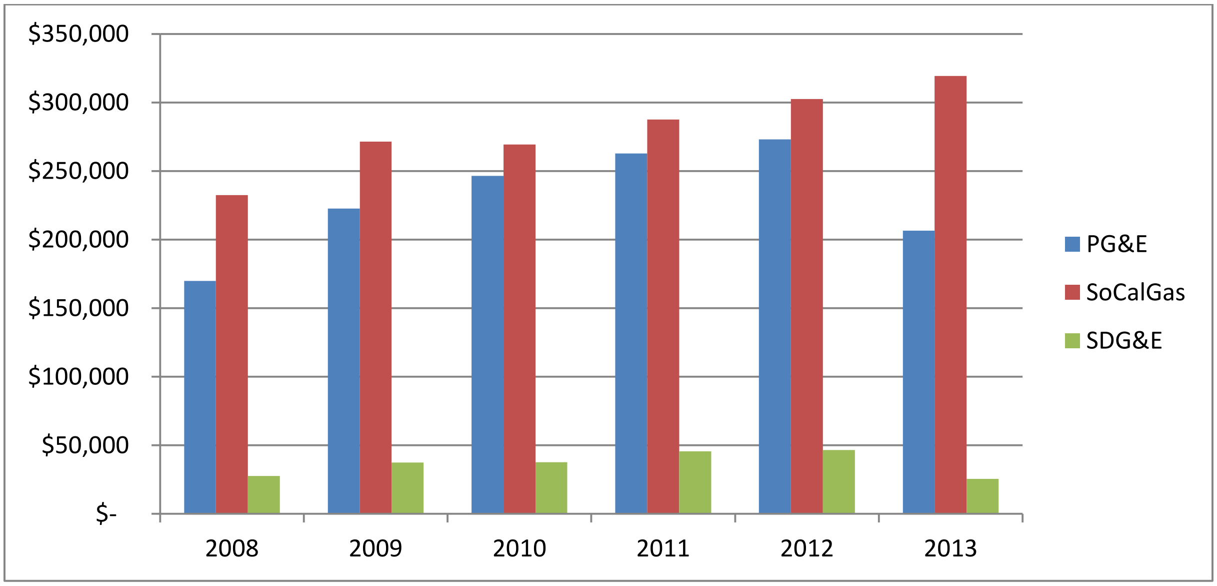


Table 6.11: Historic Revenue Requirements for Public Purpose Programs Summary ($000)

	2008	2009	2010	2011	2012	2013
PG&E	$169,869	$222,589	$246,480	$262,869	$273,008	$206,563
SoCalGas	$232,437	$271,411	$269,412	$287,564	$302,506	$319,252
SDG&E	$27,591	$37,482	$37,568	$45,583	$46,583	$25,466
Total	**$429,897**	**$531,482**	**$553,460**	**$596,016**	**$622,097**	**$551,281**

Appendix A: AB 67 Table— 2013 Electric Revenue Requirement

(in thousands of dollars)

	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 A: AB 67 Table— 2012 Electric Revenue Requirement

(in thousands of dollars)

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total	-	-	**5,889,217**	**5,520,312**	**1,292,866**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	600,632	1,994,844	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	1,988,467	1,929,082	275,540
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	775,999	w/QFs	186,040
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,501,570	1,596,386	580,088
Other		CPUC Decisions, Resolutions	22,550	0	195,196
Transmission Total			**1,043,088**	**633,256**	**371,778**
Reliability Services	FERC Order 459		(8,477)	2,200	(4,754)
Transmission Access Charge	FERC		270,068	(30,144)	(232,773)
Transmission Owner Rate Case Revenues	FERC		866,279	661,200	614,514
Other - FERC Rate Case Revenues	FERC		(84,782)	0	(5,209)
Distribution Total			**4,152,446**	**4,047,396**	**1,129,257**
AMI/Smart Meter		CPUC Decisions	220,408	187,830	(65,000)
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,839	28,000	10,035
California Solar Initiative		CPUC Decisions	121,295	110,000	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	(2,263)	98,835	20,521
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	0	0
General Rate Case Revenues		CPUC Decisions	3,647,709	3,584,033	985,403
Hazardous Substance Mechanism		CPUC Decisions	17,329	9,616	536
Energy Efficiency Incentives		CPUC Decisions	22,478	18,284	11,625
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	20,729	20,460	0
Climate Smart			0	0	0
Other		CPUC Decisions, Resolutions	74,923	(9,662)	166,137
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**48,553**	**12,733**	**9,124**
Public Purpose Programs Total			**616,200**	**640,800**	**145,683**
Energy Efficiency		CPUC Decisions	380,119	402,276	63,103
Electricity Program Investment Charge		CPUC Decisions	72,082	58,529	12,730
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	87,766	64,149	10,788
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	76,233	60,471	59,061
PPP Balancing Acct				55,375	
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(329,810)**	**(340,472)**	**58,000**
-					
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**393,032**	**390,154**	**96,271**
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	**84,721**	**81,699**	**48,616**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**434,099**	**0**	**0**
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	0	**0**	**11,030**
					,162,625

† This table shows revenue requirements collected in rates, after balancing account adjustments.

* The negative $65 million for SDG&E AMI represented an overcollection from previous years. To moderate rate increases, SDG&E eliminated CSI collections in 2012 and will collect these funds in future years. SDG&E collects CPUC funds of approximately $5 million each year, but as a surcharge, and it is not included in rates. Finally, SCE and PG&E also have franchise fee charges, but these are included in other components of rates.

Appendix A: AB 67 Table— 2011 Electric Revenue Requirement
(in thousands of dollars)

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
Generation Total	-	-	**5,289,796**	**4,128,137**	**938,595**
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	299,063	1,416,515	55,831
General Rate Case Revenues		CPUC Decisions	1,875,913	1,337,741	237,738
Renewable Portfolio Standard	PUC Section 454.5(d)(3)	CPUC Decisions	901,100	w/QFs	121,063
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,212,480	1,366,806	523,963
Other		CPUC Decisions, Resolutions	1,240	7,075	0
Transmission Total			**1,201,083**	**586,091**	**430,250**
Reliability Services	FERC Order 459		31,622	4,367	19,936
Transmission Access Charge	FERC		204,302	(32,197)	5,979
Transmission Owner Rate Case Revenues	FERC		985,328	467,951	406,900
Other - FERC Rate Case Revenues	FERC		(20,169)	145,970	(2,565)
Distribution Total			**4,022,279**	**4,101,430**	**1,300,699**
AMI/Smart Meter		Report	178,386	203,474	70,572
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	29,823	28,000	10,035
California Solar Initiative		CPUC Decisions	106,077	110,000	25,000
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	(8,899)	71,162	14,527
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	0	16,491	6,184
General Rate Case Revenues		CPUC Decisions	3,626,834	3,636,425	1,161,001
Hazardous Substance Mechanism		CPUC Decisions	11,638	2,491	279
AEAP Incentives		CPUC Decisions	0	24,092	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	20,602	20,427	0
Other		CPUC Decisions, Resolutions	33,709	(11,132)	4,396
PBR Sharing Mechanism		CPUC Decisions, Resolutions	0	0	7,579
Customer Service & Safety Awards/Penalties		CPUC Decisions, Resolutions	24,109	0	1,126
Nuclear Decommissioning	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	**58,678**	**7,667**	**8,336**
Public Purpose Programs Total			**678,335**	**687,481**	**128,033**
Energy Efficiency, PUCode 399.8	PUC Section 399.8	CPUC Decisions, E-3792	120,588	125,013	13,640
RD&D PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	35,218	28,563	5,902
Renewables, PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	36,826	29,924	7,810
Energy Efficiency, non-PUCode 399.8		CPUC Decisions	235,061	379,868	33,860
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	93,454	63,414	10,788
CARE Adm., CARE amortized in rates	PUC Section 739.1, 739.2	CPUC Decisions	157,188	60,699	56,033
DWR Power Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**(226,827)**	**610,465**	**169,000**
-					
DWR Bond Charge Revenues	AB1X, Water Code, Division 27	CPUC Decisions	**388,993**	**391,495**	**94,770**
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	**627,176**	**590,718**	**62,615**
Energy Recovery Bonds (PG&E only)	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	**404,531**	**0**	**0**
Franchise Fee Surcharge	PUC Sections 6350-6354, 6231	CPUC Decisions	0	**17,893**	**17,505**
-					
ELECTRIC TOTAL			**12,444,044**	**11,121,377**	**3,149,803**

Appendix A: AB 67 Table— 2013 Gas Revenue Requirement
(in thousands of dollars)

	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**