



# Gas and Electric Utility Cost Report

## Public Utilities Code Section 747 Report to the Governor and Legislature



# April 2010



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# I. Introduction

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Enacted as AB 67 in 2005, PU 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 electrical and gas companies regulated by the Commission. The report is to be submitted to the Governor and the Legislature by April 1<sup>st</sup> 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 the above statutory requirements of Section 747 (b).

## Background

The State of California has been a national leader in gas and electric energy policy, setting innovative mandates for market restructuring, renewable energy, demand side management, and greenhouse gas regulation. With the implementation of these policies, the utilities' cost structures and rate setting process have become increasingly complex. The funds that the utility is authorized to collect in rates to meet all 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.

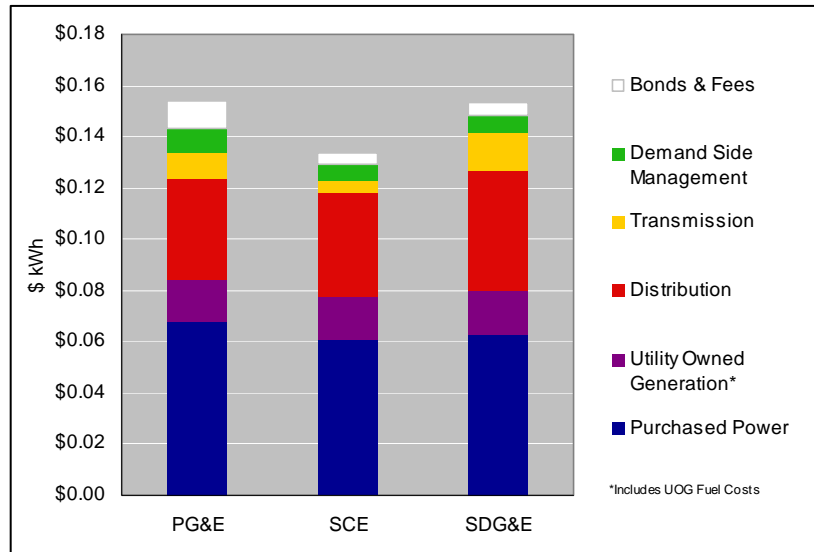
Compared to the earlier reports, the 2009 Gas and Electric Utility Cost Report (Report) provides a more detailed narrative of various energy policies in California to provide the reader with the necessary context to understand what drives electric and gas rates. The report presents a breakdown of all of the major components that contribute to gas and electric rates along with charts and tables showing how these costs and rates have varied over time since 2003.

The Report presents an analysis of the authorized revenue requirements and cost analyses for the four California investor-owned utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E) and Southern California Gas Company (SoCal Gas). “Authorized revenue requirements” are the amounts of revenues that the utilities are authorized to collect from customers. Using sales forecasts, the rates are set to collect the authorized revenue requirement. To the extent that actual sales end up being different from forecasted sales, the utilities may end up collecting 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. Thus, the utilities in the end only collect authorized revenue requirements.

## Overview—Electric Utility Costs

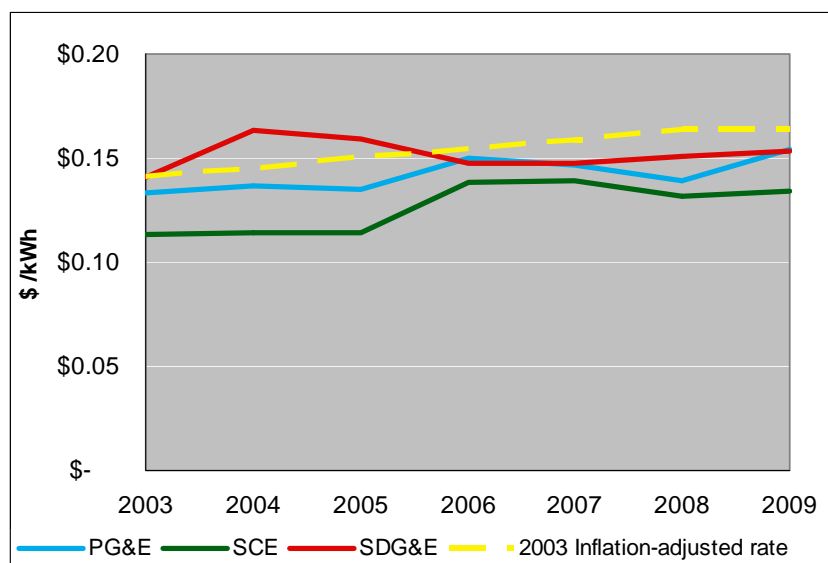
- **Electric generation and energy procurement is the largest component of electric rates.** Generation, provided through utility owned generation and purchased power sources, collectively accounts for 56% of the total revenue requirement.

**Figure 1.1 2009 Rate Components**



- **System Average Rate increases have tracked inflation.** Between the years of 2003 and 2009, the system average rates increased at an annual average of 2.7%, compared with the 2.7% average annual inflation rate since 2003. Figure 1.2 shows the trend in average electric rates for PG&E, SCE and SDG&E. In 2009, PG&E's system average rate was 15.4¢ /kWh, SCE's was 13.4¢ /kWh and SDG&E's was 15.3¢ /kWh.

**Figure 1.2 Trends in System Average Rates track inflation**



- Demand side management has been a cost effective method to meet new demand.**  
 Demand response and energy efficiency programs provide ratepayer savings that are greater than the program costs. Based on the Commission’s cost/benefit studies of demand response and energy efficiency verification reports, ratepayer savings have outweighed ratepayer costs by \$416 million. The cost/benefit study for distributed generation programs is scheduled to be released in mid-2010. In other words, demand side management expenses replace energy procurement expenses, as well as enabling deferred investment in transmission and distribution.

**Table 1.3 2009 Demand Side Management Expenses (000)**

	PG&E		SCE		SDG&E	
	Costs	Savings	Costs	Savings	Costs	Savings
Energy Efficiency*	\$399,472	\$561,574	\$337,329	\$514,406	\$97,410	\$123,897
Demand Response	\$80,779	\$134,741	\$47,803	\$113,355	\$15,390	\$25,767
<b>Total Costs/Savings</b>	<b>\$480,251</b>	<b>\$696,315</b>	<b>\$385,132</b>	<b>\$627,761</b>	<b>\$112,800</b>	<b>\$149,664</b>

\* From CPUC Energy Efficiency Verification Reports. Energy efficiency includes low income energy efficiency programs.

- Renewable Portfolio Standard eligible energy remains a small but growing component of the revenue requirements.** PG&E, SCE, and SDG&E collectively served 15% of their 2009 retail electricity load with renewable power, with a total of 1049 MW of renewable capacity installed. The CPUC has approved over 130 RPS contracts for more than 12,000 MW of capacity, some of which will not come on line for various reasons.

## Overview—Gas Utility Costs

- Total natural gas utility costs in 2009 were much lower than in recent past years** due to a significant decrease in the price of natural gas.
- Revenue requirements for natural gas transmission, distribution and storage systems**, and for providing various customer services, have moderately increased in recent years.
- Costs authorized by the CPUC for natural gas public purpose programs have increased since 2006**, primarily due to significant increases for energy efficiency, low-income energy efficiency, and natural gas research and development programs.

The remainder of this report provides a breakdown of the various cost components and identifies the components that have experienced the greatest increase. In addition to the detailed summary tables provided throughout the text, Appendix A provides summaries of the IOU revenue requirements organized according to the rate components typically shown on customer bills.

## Determining Revenue Requirements

Due to the varied nature of the utility costs and the multitude of energy policy programs, the determination of revenue requirements and rate-setting process at the CPUC has grown more complex over time. Some categories of costs are determined in the general rate cases, while others are determined through the Energy Resource Recovery Account. In addition, budgets for each program area are determined in separate program proceedings.

The utilities earn a rate of return or profit only on items of cost that are capitalized (e.g. assets and equipment). For many cost categories such as purchased power and fuel cost, they are only reimbursed for their cost. There is no mark-up or profit on the cost. These cost items are commonly referred to as pass-through costs. The revenue requirements the utilities are authorized to collect from customers are determined chiefly in the following forums:

1. General rate cases 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 Commission reviews each utility's fuel and power purchase cost forecasts and passes through the revenue requirements without allowing any profit or mark-up to the utility.
4. Specific program area proceedings where the program budget is determined.

### **Categorization of Utility Costs**

Utility costs or revenue requirements are categorized into three major categories: generation, distribution and transmission. This categorization not only reflects major areas of utility operations but is also used to decide which customer classes would pay for which categories of costs. The latter is important because some utility customers do not receive full or bundled service from the utility. Instead they may generate their own power on site or buy power from a non-utility source (e.g. electricity service providers or ESPs or a community choice aggregator). Such customers are not charged for the generation cost by the utility and pay only the transmission and distribution cost. Additionally, some large customers may be receiving service at transmission voltage level and do not use the utility distribution system.

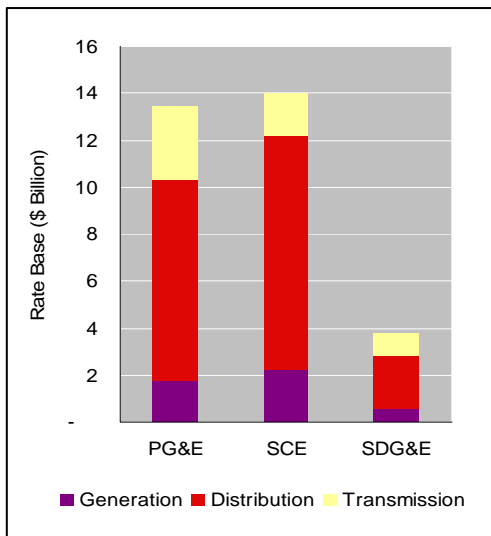
**Table 1.4 2009 IOU Revenue Requirement Summary (000)**

	PG&E	SCE	SDG&E
Generation/Energy Procurement			
Purchased Power	\$5,519,482	\$5,374,090	\$1,297,324
Utility Owned Generation	\$1,384,669	\$1,396,701	\$358,125
Distribution	\$3,204,148	\$3,606,231	\$968,276
Transmission	\$789,450	\$447,433	\$288,773
Demand Side Management	\$778,992	\$544,248	\$145,944
Bonds & Fees	\$916,160	\$399,262	\$103,505
<b>Total 2009 Revenue Requirement</b>	<b>\$12,592,901</b>	<b>\$11,767,965</b>	<b>\$3,161,947</b>

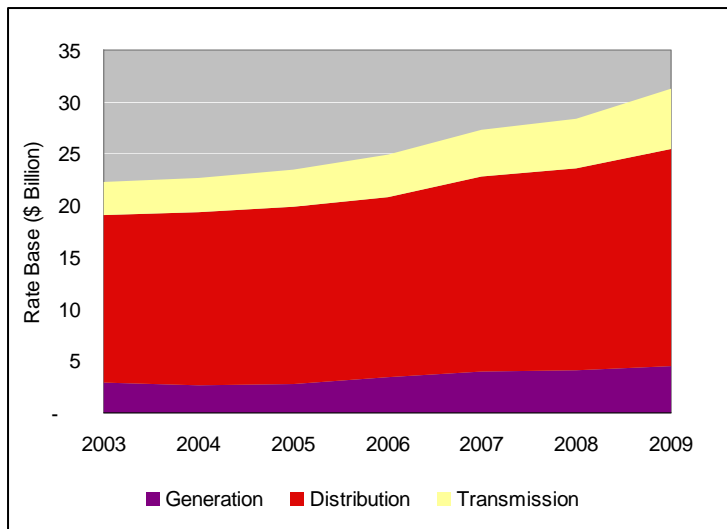
## Rate Base

The rate base is the book value of the generation, distribution and transmission infrastructure owned and operated by the utility after depreciation. Other things equal, a higher rate base results in a higher net income for the utility and vice versa as the utilities' total return is based on the remaining book value of their assets or rate base. As assets are depreciated over time, the rate base declines. Rate base increases when utilities build new plant and infrastructure or make capital additions and improvements that are treated as capital improvements. Changes in rate base also result in changes in depreciation allowance the utility is authorized to collect. From 2003 to 2009, IOU rate base increased from \$22.3 billion to \$31.2 billion, leading to the increases in the GRC revenue requirements.

**Figure 1.5 2009 Rate Base**



**Figure 1.6 Trends in Rate Base**



## II. General Rate Case (GRC) Revenue Requirements

The costs that can be fairly accurately predicted and budgeted are examined and approved by the Commission in General Rate Case proceedings (GRCs). These proceedings usually are on a 3 year cycle for the major utilities and even on a longer cycle for the smaller utilities. In the GRC proceedings, the Commission sets a pre-specified revenue requirement for the first year called the “test year” with pre-specified formulaic adjustments for the following years (commonly called attrition years) until the next GRC decision goes into effect.

If the utilities’ actual expenditures turn out to be more or less than the level adopted by the Commission in a GRC proceeding, the utilities’ authorized revenue requirement stays the same unless it was specified differently. This GRC ratemaking with pre-specified budgets is adopted with the goal to provide utilities an incentive to stay within the approved budgets. With this ratemaking treatment, utility profits suffer if they spend more than the GRC authorized revenue requirement and vice versa.

Approximately 45% of the utilities’ revenue requirements are set in general rate cases at the CPUC and at FERC. The remaining 55% consists of pass-through costs determined to be reasonable by the CPUC. The transmission revenue requirement is determined by the Federal Energy Regulatory Commission (FERC) in transmission owner rate cases following similar test year rate making.

The major components of costs that are reviewed and determined in the GRCs include the following major elements:

**Table 2.1 2009 General Rate Case Revenue Requirements (000)**

	<b>PG&amp;E</b>	<b>SCE</b>	<b>SDG&amp;E</b>
Operations and Maintenance	\$1,827,122	\$1,853,119	\$445,646
Depreciation	\$1,019,254	\$1,106,992	\$285,756
Return on Rate Base	\$909,993	\$1,066,918	\$246,799
Taxes	\$617,138	\$819,612	\$176,474
<b>Total</b>	<b>\$4,373,507</b>	<b>\$4,846,641</b>	<b>\$1,154,675</b>

(Excludes FERC determined transmission revenue requirements)

- **Operations and Maintenance (O&M):** These costs include all operations and maintenance costs such as facility upgrades and additions, staffing costs for utility owned 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 dictate as to where the utilities must spend the money and how much. Depending on how they manage various projects and prioritize the budgets, the utilities may end up spending 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:** All of the capital investment in utility facilities and assets is financed by the utilities using their own funding sources. The capital they spend on financing these assets is returned to them over specified time periods in the form of 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 items of expenses, the Commission provides them a rate of return on their invested capital. Rate of return is the weighted average cost of debt and shareholder equity. The Commission allows a fair and reasonable return that is sufficient to allow continued flow of needed capital. 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 all of 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 authorized GRC revenue requirements. If they are able to keep their costs below the forecasted costs and authorized revenues, they can boost their profits above the authorized level and vice versa.

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) and the gas cost incentive mechanism whereby the utilities share in the savings or cost reductions with ratepayers. The utilities are not allowed a mark-up or profit on purchased power and fuel costs which are pass through costs.

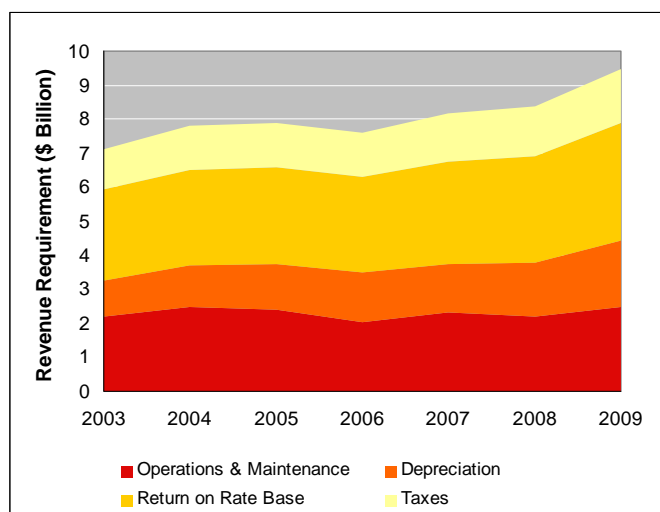
## **Distribution Revenue Requirement**

Since 2003, the depreciation expenses have experienced the greatest increase among the distribution revenue requirements, with a 14% average annual growth rate. O&M and Return on Rate Base increased by 2.3% and 4.6% respectively. During this period, the increases in distribution costs were primarily due to capital additions and infrastructure improvements to the distribution system. These distribution infrastructure investments led to increases in rate base, as discussed on page 8.

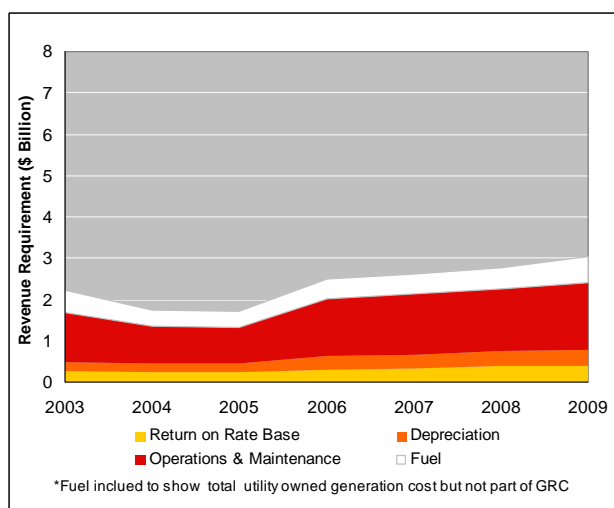
**Table 2.2 2009 Distribution Revenue Requirements (000)**

	<b>PG&amp;E</b>	<b>SCE</b>	<b>SDG&amp;E</b>
Operations and Maintenance	\$1,080,678	\$1,075,751	\$332,802
Depreciation	\$803,838	\$879,113	\$260,231
Return on Rate Base	\$1,370,528	\$1,693,370	\$373,694
<b>Total</b>	<b>\$3,255,044</b>	<b>\$3,648,234</b>	<b>\$966,727</b>

**Figure 2.3 Trends in Distribution Revenue Requirement**



**Figure 2.4 Trends in Generation Revenue Requirement**



## Utility Owned Generation (UOG) Revenue Requirement

The revenue requirement for utility owned generation includes O&M costs, depreciation and return on rate base related to these facilities. As the old generating plants depreciate, these costs go down over time, unless new plants are built by the utilities or capital improvements are made to the existing facilities. UOG revenue requirement experienced some recent increases due to the nuclear steam generator replacements by SCE and PG&E and with the addition of some peaking capacity. O&M expenses for generation also increased in 2006 while they decreased for distribution, because some Administrative and General Expenses were recategorized as generation expenses in the GRC.

While the majority of the UOG revenue requirement is authorized in the GRC, fuel costs are authorized annually through ERA because the fuel prices fluctuate with the market. Following restructuring and divestiture of fossil-fueled generation, UOG today accounts for only 32% of the combined utility supply portfolio and 13% of their combined revenue requirements.

**Table 2.5 2009 Generation Revenue Requirements (000)**

	PG&E	SCE	SDG&E
Operations and Maintenance	\$746,444	\$777,368	\$112,844
Depreciation	\$135,416	\$213,226	\$25,525
Return on Rate Base	\$156,603	\$193,160	\$49,579
<b>Total</b>	<b>\$1,038,463</b>	<b>\$1,183,754</b>	<b>\$187,948</b>

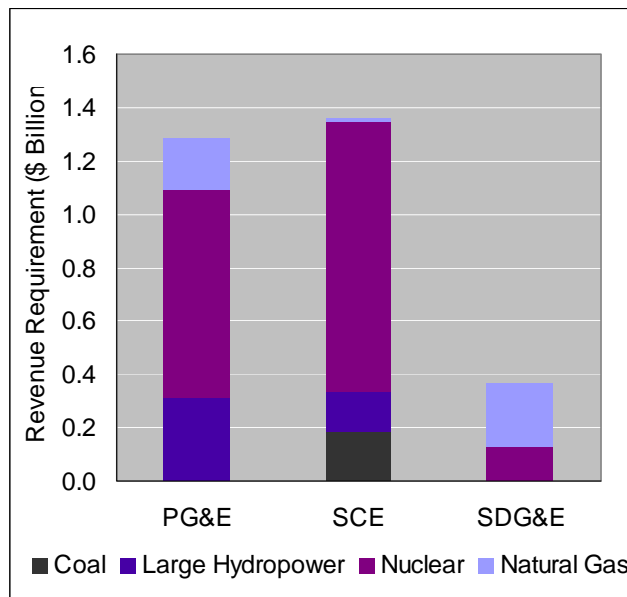
Utility owned generation for PG&E consists primarily of hydro-electric and nuclear power (Diablo Canyon) plants. SCE's UOG portfolio consists primarily of coal (with a joint ownership stake in Four Corners Generating Facility in Arizona) and nuclear. SCE's reliance on coal has substantially decreased since the Mohave Generating Station has been taken out of service. SDG&E and SCE hold joint ownership in San Onofre Nuclear Generating Station.<sup>1</sup> SCE also holds partial ownership in Palo Verde Nuclear Generator in Arizona. Due to capital investment in new steam generators, nuclear generation revenue requirements have increased the most among UOG sources, at an average annual increase of 4.6% per year.

The utilities divested most of their natural gas generation capacity in 1998, but SCE and SDG&E have recently constructed natural gas peaking plants which have resulted in increases in UOG revenue requirements.

Besides the O&M, depreciation and return authorized in GRC proceedings and fuel costs, nuclear generation also requires the following additional costs, which are collected as separate revenue requirements:<sup>2</sup>

- **Disposal and storage of spent nuclear fuel** are fees required by the US Department of Energy for temporary and permanent storage facilities
- **Nuclear decommissioning** of generating plants at the end of their lives. Costs for fuel disposal and decommissioning are authorized and regulated separately through the Federal Nuclear Regulatory Commission

**Figure 2.6 Revenue Requirements of UOG Sources**



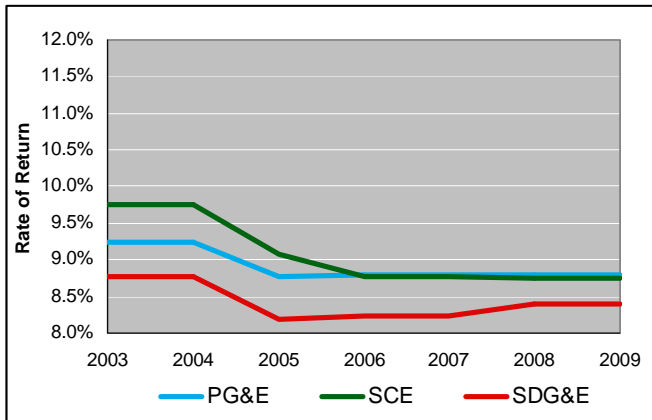
<sup>1</sup> In addition to the list of UOG resources above, SCE also owns and operates a diesel generating facility on Santa Catalina Island. Since the island's load is not connected to the grid, the supply and demand are not included in the forecasts, but the expense is included in the revenue requirements.

<sup>2</sup> Nuclear Decommissioning and DOE Decommissioning & Disposal expenses are listed in the Bonds & Fees section.

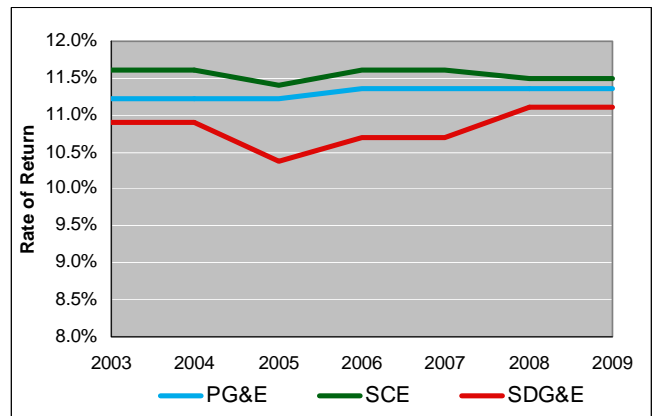
## Authorized Rate of Return

The following charts show the rate of return authorized by the Commission since 2003 for each utility. They do not include the rate of return authorized by the FERC for IOU transmission systems. It only includes return authorized by the CPUC for utility owned generation and distribution.

**Figure 2.7 Trends in Weighted Average Rate of Return**



**Figure 2.8 Trends in Return on Equity**



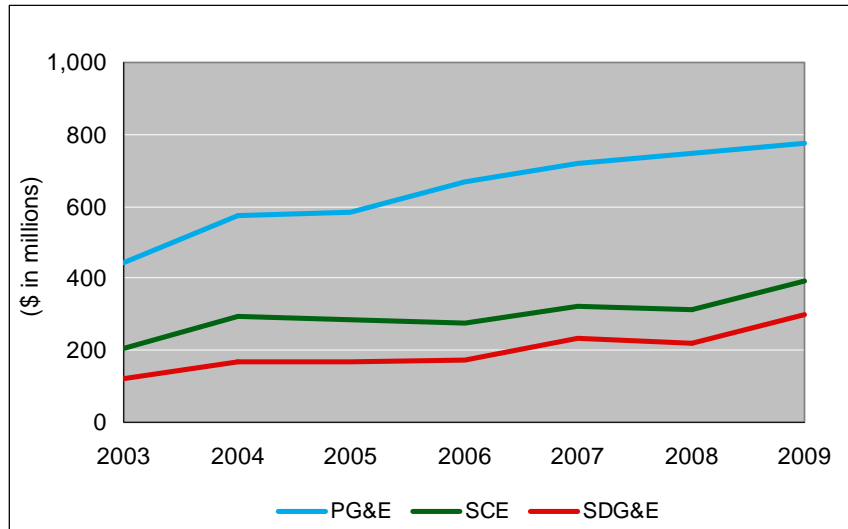
## Transmission Revenue Requirements

As part of energy restructuring, the California Independent System Operator (CAISO) was created and given operational control over the utilities' high voltage lines on January 1, 1998. With that, the authority for determining transmission revenue requirements was transferred to FERC. The transmission revenue requirements authorized by FERC involve the same major revenue requirement components (O&M, depreciation and return on rate base) as the general rate cases at the CPUC. However, most of the time, the transmission revenue requirement at FERC is reached through settlements and adopted as a "black box" number without a breakdown of the components. Therefore, the Commission does not have the same information to report and analyze for transmission as it does for generation and distribution.

The transmission revenue requirements vary significantly for each utility. One reason for the difference is that each utility defines high voltage lines somewhat differently. PG&E defines all power lines at 60kV and above as transmission and includes them in the transmission revenue requirement, while SCE and SDG&E respectively include all lines above 200kV, and at 69kV and above in transmission revenue requirement. For this reason, transmission constitutes a larger percentage of PG&E and SDG&E's costs than that of SCE.

Transmission revenue requirement for the three utilities have experienced varied annual growth rates since 2003. Individually, PG&E's transmission revenue requirement increased at a 13% annual average, SCE's at 15% and SDG&E's at 24%.

**Figure 2.9 Trends in Transmission Revenue Requirements**

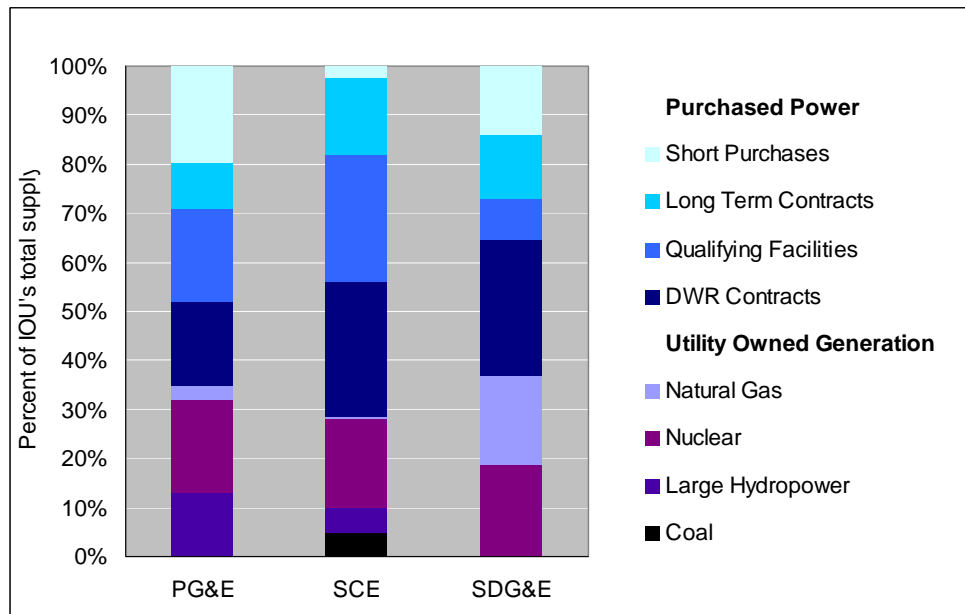


### III. Power Procurement Costs

Generation revenue requirement includes all the revenue requirements associated with utility owned generating (UOG) facilities, discussed in Chapter 2, as well as purchased power costs. Upon electric restructuring, utilities divested almost all of their fossil fueled generating plants and have been relying mainly on purchased power for incremental electricity needs. In 2009, purchased power accounted for 81% of the total generation revenue requirement while utility owned generation revenue requirement comprised only 19%.

Out of total energy generation costs, power purchases represent the largest component, accounting for 46% of the total revenue requirements, and have increased, on average, by 5.1% per year. There is no mark-up for the utilities or profit in purchased power expenses. Recovery of these costs is authorized through the Energy Resource Recovery Account (ERRA) proceedings and not through the GRCs.

**Figure 3.1 2009 Energy Supply**



#### **Background**

Heavy reliance on power purchases instead of utility owned power plants began with the enactment of AB 1890, which restructured the electric utility industry in California and created the Independent System Operator (CAISO) and the Power Exchange (PX). To create a competitive electricity market where non-utility suppliers would compete with the utilities in the generation market, utilities were exhorted 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 part of this program, the utilities did divest themselves of a substantial part of their fossil-fueled generation.

During the Energy Crisis of 2000-2001, utilities were more exposed to spiking market prices for electricity, due to divestiture of generation. Authorized utility rates (which were frozen at pre-

restructuring June 1996 levels) were no longer sufficient for the utilities to cover the high prices of purchased electricity; PG&E filed for bankruptcy and SCE and SDG&E both faced substantial financial uncertainty. Given the financial situation of the utilities in January 2001, 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. An essential component of the stability of energy markets was Resource Adequacy (RA)—the measure to ensure that the investor owned electric utilities would arrange for sufficient generation beforehand to meet load growth. The legislation also required the Commission to adopt a Long Term Procurement Plan to ensure sufficient resource availability over time. Additionally, AB 57 established guidelines for procurement solicitations, cost recovery of power purchases and integrating renewable resources into long term planning.

As part of the reforms following the Energy Crisis, the CAISO has redesigned its market structure and rules. The initiative is called the Market Redesign and Technology Upgrade (MRTU). MRTU went operational in the spring of 2009. With MRTU, market price is determined using many (approx 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 should make the electricity industry more efficient by accurately and transparently pricing generation and identifying areas where transmission upgrades may be cost effective.

## **Types of Purchased Power**

### **DWR Contracts:**

These are long term contracts that the Department of Water Resources entered into on behalf of the IOU's customers during the Energy Crisis when the three largest investor-owned electric utilities were no longer creditworthy. Each year, DWR submits its revenue requirement with the Commission for adoption and subsequent collection from ratepayers through the DWR Power Charge. The total energy supply provided by DWR has been decreasing since 2003 as the contracts expire. The majority of the contracts will expire between 2010 and 2012, and the final contracts are scheduled to expire by 2015. There is also a DWR bond charge that is collected separately in electric rates. As discussed further below, these bonds were issued to repay the money the State spent to purchase power during the early days of the Energy Crisis.

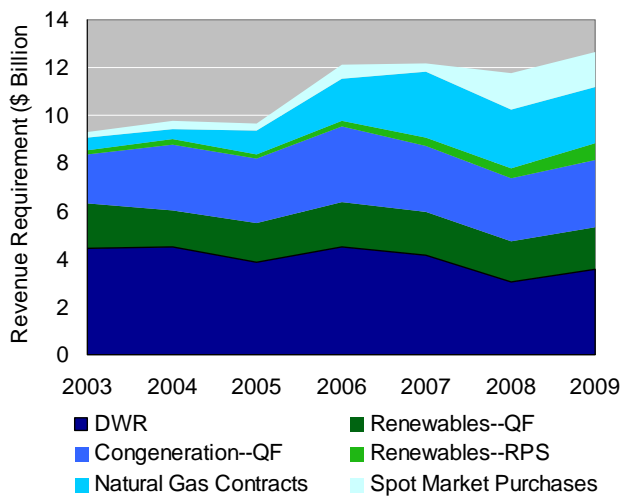
### **Qualifying Facilities (QFs):**

Qualifying Facilities are generators that qualify to sell power to the utilities under the Federal Public Utilities Regulatory Policies Act (PURPA). These facilities have to meet the Federal Energy Regulatory Commission's requirements for ownership, size and efficiency to qualify as QFs. PURPA requires investor-owned utilities (IOUs) to interconnect with and purchase power from Qualifying Facilities (QFs) at rates that reflect costs the utility avoids by buying QF power

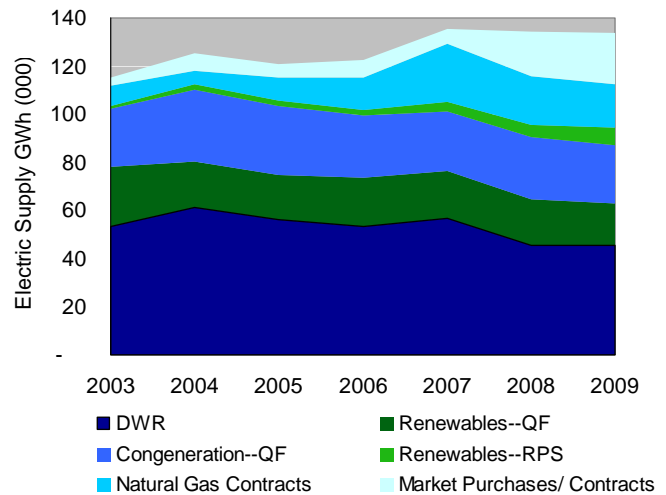
instead of procuring power from other sources. In California, the avoided cost is the amount the utility would have incurred to build new gas-fired generation but for the existence of the QFs.<sup>3</sup>

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 Qualifying Facilities has decreased by 14% since 2003 as older contracts expire, while QF power related revenue requirement has increased by 6.3% due to increases in gas prices, further discussed on page 18.

**Figure 3.2 Trends in Purchased Power Revenue Requirements**



**Figure 3.3 Trends in Purchased Power Supply (GWh)**



**Bilateral 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 an open solicitation (Request for Offers or RFO) process, which is reviewed by “Procurement Review Groups” created within the CPUC’s procurement proceedings.

Bilateral contracts represent a larger part of the utility power procurement portfolio now as the utilities need to replace expiring DWR contracts as load grows. Because these are mostly long-term contracts, bilateral contracts cost more in c/kWh. The revenue requirements from bilateral contracts have increased over 52% annually, and the average cost (c/kWh) for bilateral contracts has increased by 14%, making this the most costly form of energy procurement in the market. There are a few factors that, in combination, help to explain this trend. First, natural gas prices spiked in 2006 as a result of Hurricane Katrina in the Gulf of Mexico gas producing region, and have been extremely volatile since then. Although gas prices had dropped by 2009, the utilities’ 2009 revenue requirements were based on gas price forecasts during 2008. Secondly, in 2004, Commission Decision 04-10-035 and 04-01-050 required LSEs to maintain a Planning Reserve

<sup>3</sup> QF costs include Competition Transition Charges (CTC). For a breakout, see table in Appendix A.

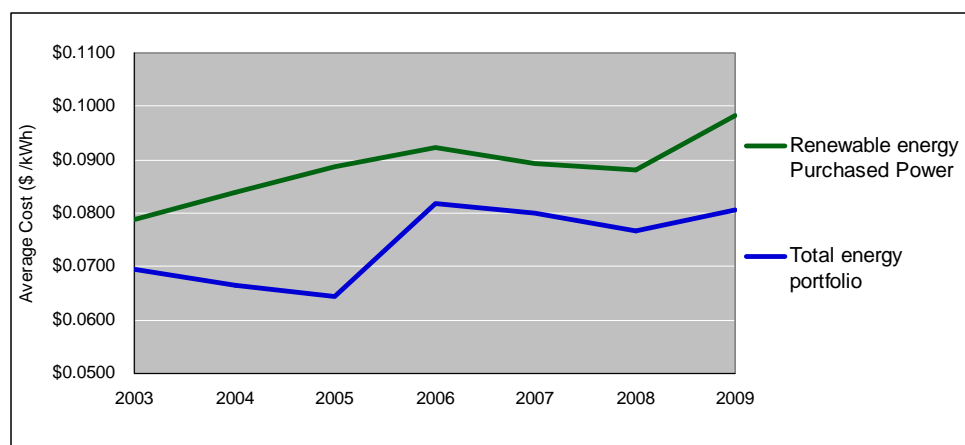
Margin 15% above peak load for all months of the year, which increased the utilities' capacity requirements. The increased capacity requirements are primarily met through contracts with natural gas fueled generators. Because resources held in reserve are over and above expected load, they may not operate during the year, making them very expensive on a per kWh basis.

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 200 hours per year. Natural gas fueled generation is often the resource best able to supply peaking capacity. Peaking capacity is generally higher in c/kWh cost because it is used in only few peak hours per year and thus costs are spread over fewer hours. Increased use of wind and solar generation increases the need for peaking capacity to fill in at times when the wind is not blowing or the sun is not shining.

### 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.<sup>4</sup> Eligible resources include wind, large scale solar, tidal wave, small hydroelectric, geothermal, biodiesel, biomass, and biogas. In 2008, Governor Schwarzenegger expanded the Renewable Portfolio Standard by Executive Order, raising the renewables goal to 33% of the state's energy requirements by 2020. This mandate has made renewable energy central to the state's core procurement planning. However, renewable energy revenue requirements remain a relatively minor component in the total portfolio at present, 9% in 2009. Figures 3.2 and 3.3 show the renewable energy revenue requirement and supply, respectively. Qualifying Facilities contracts comprise the majority of the RPS eligible supply, while new RPS eligible sources are also procured through bilateral contracts. As of 2009, the average cost of renewable energy is **20% higher than** the prices of the remaining energy portfolio, as seen in Figure 3.4. The Commission forecasts that the cost for additional renewable sources will rise. Existing sources took advantage of the lower cost opportunities, while planned future resources may have higher projected costs.

**Figure 3.4 Average cost of RPS eligible sources and total energy portfolio CORRECTED**



<sup>4</sup> The RPS was subsequently modified by SB 107 in 2006 and SB 1036 in 2007.

## 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, which combined accounted for 3% of the revenue requirement in 2009.<sup>5</sup>

- **Capacity Contracts:** The utilities are required to maintain a 15-17% planning reserve margin for generating capacity to handle unplanned plant outages and situations where actual peak load may be above the forecast. This means that they have to make sure that they have 15% more capacity resources than their forecasted load.<sup>6</sup> The resource adequacy requirement ensures that the IOUs have contracts that have reserved supply resources months in advance to ensure that the capacity will be available to meet their load.
- **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 system on a day to day basis. IOUs use the spot market to balance their forecasted load requirement for the following day through transactions that may occur in the CAISO market or independently. Spot market purchases accounted for 11% of the revenue requirement.
- **Net long sales:** These are sales that the utilities make when they have more supply resources compared to their forecasted load. Such sales reduce ratepayer costs by selling excess capacity not likely to be needed. In most years, their spot market sales are greater than the IOUs' spot market purchases.
- **Inter-utility or Power Exchange Agreements:** Traditionally, regulated utilities enter into seasonal and long-term inter-utility exchange agreements (IUE) with other regulated utilities and other load-serving entities. Through bilateral negotiation 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 ISO spreads its costs of procuring these reliability services among the load serving entities. In addition, the ISO buys power in the real time market to balance the load and bills the load serving entity whose short supply necessitated the real time purchases.

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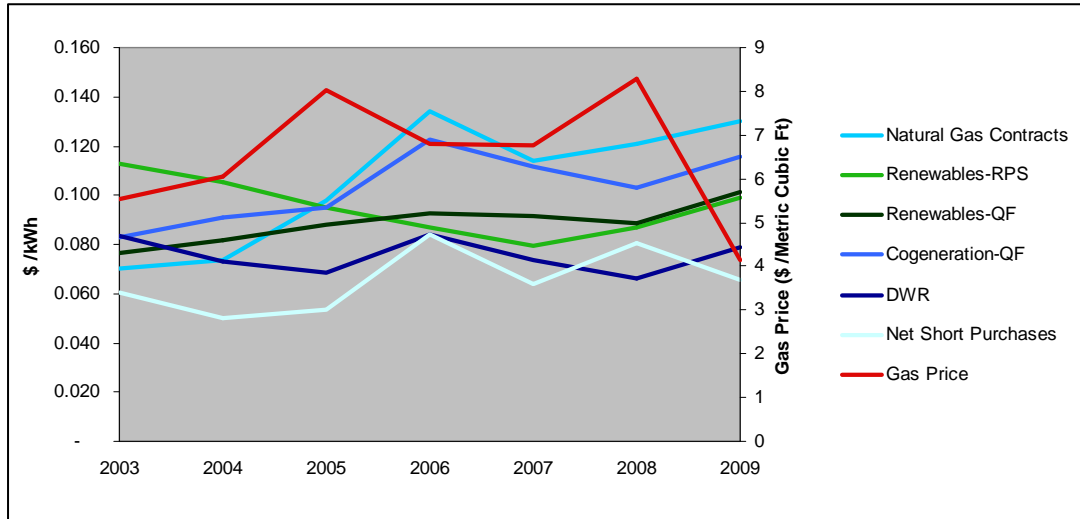
<sup>5</sup>Utility options for market transaction are defined in D. 02-10-062. A breakout of margin sales and purchases is Confidential/privileged information pursuant to applicable provisions of D.06-06-066, G.O. 66-C and PUC Code Sec. 583 and Sec. 454.5(g).

<sup>6</sup> Mandate for Capacity Reserve Requirement was set in D.04-10-035. It is currently under review in R.08-04-012.

## Factors affecting generation costs

Energy generation and procurement costs can vary significantly over time due to a number of factors that influence energy costs. Figure 3.5 shows the average costs of various types of purchased power.

**Figure 3.5 Average Cost for Purchased Power**



The following factors influence energy costs:

- **Peaking and firming capacity.** Generation sources for peaking and firming load is gas-fired because gas-fired units are quick start units. Because peaking capacity is used only over a few peak hours in the year, the cost /kWh is high. Lately, the utilities have added such new peaking capacity to help meet overall capacity requirements. As a result, UOG natural gas fired generation cost is high.
- **Bilateral contracts.** Bilateral contracts can be a higher cost resource since these are long term resources where the supplier tries to recover all costs of the generating plant through the single contract. In comparison, spot and short term purchases are sometimes lower because the supplier has an existing resource and is willing to sell at less than full cost to minimize loss. With the lessons learned from events leading to the Energy Crisis, the Commission and the Legislature have determined that it is not prudent for the utilities regulated by the Commission to rely on spot market purchases excessively, but instead should have a more diverse portfolio. That is why the Commission requires long term resource planning and resource adequacy. The main reason spot market prices are lower is that the utilities are buying very little in the spot market, so there is more supply than demand in the spot market at times. One can also think of the higher price of long term contracts as a “hedging cost” or “hedging premium” over spot market prices to ensure certainty and stability of prices in the future.
- **Natural gas prices.** Gas prices make natural gas generation more volatile than other forms of generation. Spot market purchases, DWR contracts, cogeneration QFs, natural gas bilateral contracts, and UOG natural gas generation have greater fluctuations than the other

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generation. The cost of natural gas fired generation peaked in 2006 with the spike in gas prices after Hurricane Katrina.

- **Depreciation costs.** Older, utility owned baseload generation costs less now because the utilities have already substantially recovered their investment in these plants. As a result, ratepayers do not have to pay high amounts of depreciation and rate of return on these assets any more. Because UOG hydroelectric, coal and nuclear facilities are all older plants their costs are between \$.02 and \$.05 /kWh.

## IV. Demand Side Management & Customer Programs

Demand Side Management involves various programs and activities on the customer side of the meter to curtail or shift demand for electricity through energy efficiency, demand response, and distributed generation. In 2003, the CPUC and the CEC adopted the Energy Action Plan to establish goals for the state's energy strategy.<sup>7</sup> 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 offering financial incentives through customer programs to encourage the development of demand side management, 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 23% average annual increase since 2003, as CSI, AMI and demand response programs were initiated, and energy efficiency programs doubled in size. Cost/benefit studies have shown that in total, the collective costs of these programs are less than the financial savings created by reducing the demand for additional generation. In total, demand side management programs combined account for 5% of the total revenue requirement, however the revenue requirement does not incorporate the savings. When savings are accounted for, demand side management programs collectively provide \$416 million in net savings<sup>8</sup> to ratepayers, which more than compensates for their costs.

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 Demand Side Management Expenses in 2009**

	<b>PG&amp;E</b>	<b>SCE</b>	<b>SDG&amp;E</b>
Energy Efficiency: Public Goods Charge	\$117,992	\$99,293	\$34,800
Energy Efficiency: Procurement charge	\$213,172	\$177,794	\$51,338
Demand Response	\$80,779	\$47,803	\$15,390
AMI	\$81,064	\$97,332	\$40,291
California Solar Initiative	\$141,436	\$100,119	\$100,119
Self Generation Incentive Program	\$30,186	\$28,000	\$6,678
<b>Total</b>	<b>\$664,630</b>	<b>\$550,340</b>	<b>\$248,617</b>

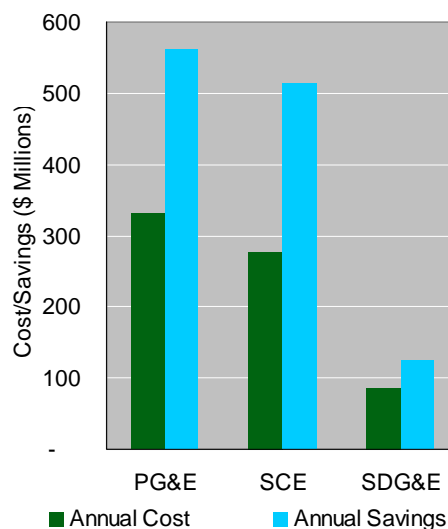
<sup>7</sup> The Energy Action Plan was updated in 2005 and 2008.

<sup>8</sup> Net Savings based on annual budgeted costs and benefits reported in Demand Response Cost/benefit Study Total Resource Cost Test, and annual verified costs and savings in 2009 Energy Efficiency Verification Report

## Energy Efficiency

During 2009, there were 218 energy efficiency programs in California directed at residential, commercial, industrial, and agricultural sectors. Prior to 2006, energy efficiency programs had largely been funded by the Public Goods Charge,<sup>9</sup> as authorized by Public Utilities (PU) Code Sections 381 and 399. 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 provided for in that decision. The Commission-adopted energy savings goals are expressed in terms of annual and cumulative gigawatt hours, million-therms and peak megawatt load reductions. In addition to the energy efficiency budget supported by the Public Goods Charge, additional funds for spending on cost-effective energy efficiency programs are also collected through the procurement component of rates. As a result, the aggregated annual budget for energy efficiency increased from \$283 million in 2003 to \$695 million in 2009, as shown in figure 4.3. The Commission's 2006-2008 Energy Efficiency Verification Reports have determined that the average annual ratepayer savings due to energy efficiency programs totaled \$1.2 billion for the 2006-2008 funding cycle.

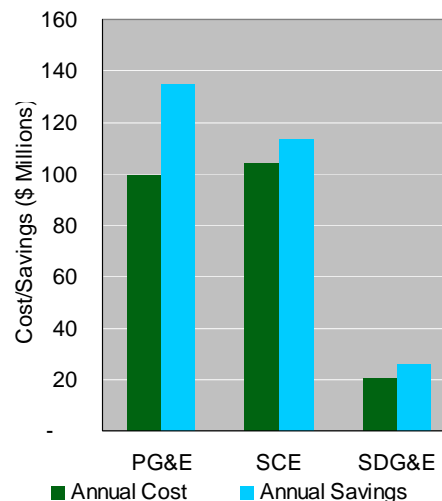
**Figure 4.2 Average Annual Costs and Savings for Energy Efficiency 2006-2008**



## Demand Response

Demand response is a resource that allows end-use electric customers to reduce their electricity usage during peak periods or shift that usage to another time period, in response to a price signal, a financial incentive, an environmental condition or a reliability signal. Demand response saves ratepayers money by lowering peak time energy usage, which is high-priced. The resulting reduction in peak demand lowers the price of wholesale energy, and in turn, retail rates. Demand response goals are met through customer programs and metering infrastructure upgrades.

**Figure 4.3 Costs and Benefits for Demand Response Programs**



<sup>9</sup> Public Good Charge established in [D.04-09-060](#)

- **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 programs, and customers are called to curtail load on designated peak days. Demand response programs can meet the needs for system reliability, or peak capacity management. The 2008 Cost/Benefit analysis found that demand response programs create a total ratepayer savings of \$274 million annually.
- **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 financial savings of AMI are twofold. By providing price and usage information, it helps the customers to make better-informed decisions about energy use, which is anticipated to reduce demand, and thus the need for new generating capacity. Secondly, it lowers the utilities' operating costs by reducing the need for manual meter reading and customer connections and disconnections and by reducing customer billing costs.

### **Distributed Generation:**

Ratepayers fund two distributed generation programs that provide financial incentives to participating customers. The cost/benefit study for distributed generation programs is scheduled to be released in mid-2010.

- **California Solar Initiative (CSI):** Established in 2006, CSI provides a front-end incentive for the installation of photovoltaic solar systems for residential and commercial customers up to 1 MW. The CSI Program has a budget of \$2.167 billion over 10 years, and the goal is to reach 1,940 MW of installed solar capacity by the end of 2016.
- **Self Generation Incentive Program (SGIP):** Established in 2001, SGIP provided incentives for the installation of a variety of distributed generation technologies, including fuel cells, biogas, distributed wind applications, solar water heating, and energy storage applications.

## **Low Income Programs**

California IOUs provide two ratepayer-funded programs for low-income customers: CARE rate discounts and the Low Income Energy Efficiency program.

**Table 4.4 2009 Low Income Program Expenses (000)**

	<b>PG&amp;E</b>	<b>SCE</b>	<b>SDG&amp;E</b>
CARE Discount	\$410,153	\$199,493	\$32,075
CARE Administrative Expenses	\$7,326	\$5,541	\$2,143
Low Income Energy Efficiency	\$68,308	\$60,242	\$11,272
<b>Total</b>	<b>\$485,787</b>	<b>\$265,276</b>	<b>\$45,490</b>

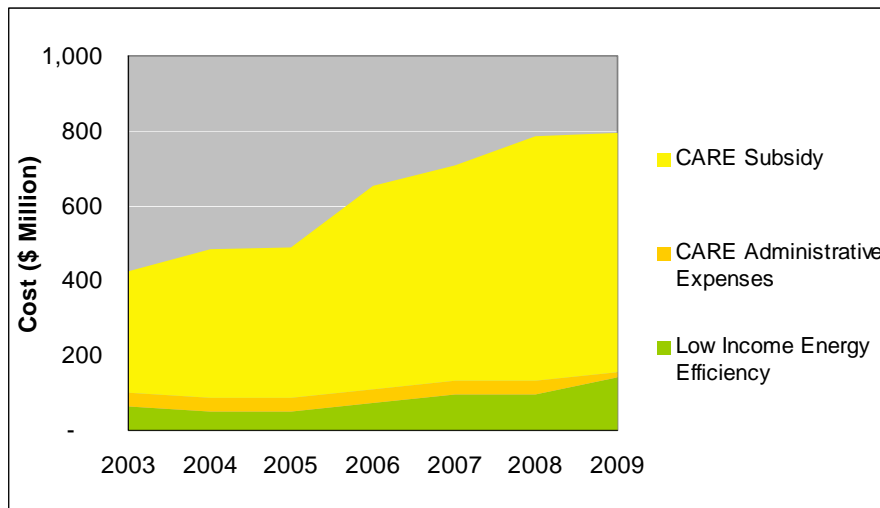
### **California Alternative Rates for Energy (CARE):**

The CARE program provides rate discounts for qualifying low-income customers. The rate discount was increased from 15% to 20% by Commission decision D.01-06-010 in 2001. In

addition, during the Energy Crisis, legislation exempted CARE customers from certain DWR power costs and kept Tier 1 and Tier 2 residential rates frozen at pre-restructuring levels per AB 1X. Additionally, CARE customers do not have Tiers 4 and Tier 5 rates for high consumption levels as non-CARE customers do. As a result, the 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 \$15 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 affect the rate that non-CARE customers pay. The PG&E CARE discount in 2009 was \$410 million, compared to SCE at \$199 million. A major reason that PG&E’s CARE discount is higher is that PG&E only has Tiers 1 and Tier 2 for CARE customers whereas SCE and SDG&E have three tiers, making PG&E’s CARE discount at high levels of consumption higher<sup>10</sup>. CARE discount costs have had a 16% average annual increase since 2003.

**Figure 4.5 Trends in Low Income Program Expenses**



**Low-income Energy Efficiency:**

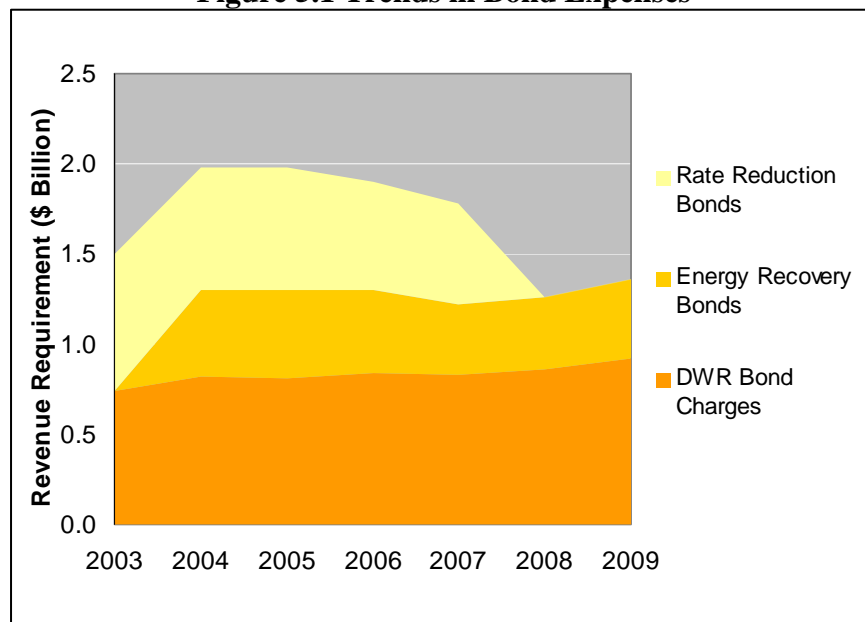
The program was mandated by legislation in 1990 as PU Code 2790, which requires gas and electric corporations to perform home weatherization services for low-income households, and defines those services to include the following “Big Six” measures: (1) attic insulation; (2) caulking; (3) weather stripping; (4) low flow showerheads; (5) water heater blankets and (6) door and building envelope repairs which reduce infiltration. Weatherization services may also include other building conservation measures, energy efficiency appliances and energy education programs. Low-income energy efficiency 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. The program accounts for 0.5% of the Revenue Requirement, and its net savings were included in the total savings calculated for the Energy Efficiency Verification Report.

<sup>10</sup> With the passage of SB 695 in October 2009, PG&E is now authorized to create a Tier 3 rate for CARE customers

## V. Bonds and Regulatory Fees

The \$1.4 billion revenue requirement for bonds constitutes the ongoing costs to ratepayers for the energy crisis of 2000-2001. During the era of electric restructuring, the State and the utilities issued a series of bonds to amortize ratepayer impacts of energy restructuring and the energy crisis related costs. Since the energy crisis, bond costs have decreased from a peak at \$2 billion aggregated revenue requirement in 2004 to \$1.4 billion in 2009.

**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 by the California Department of Water Resources in 2003 to recover costs incurred by the State of California during the energy crisis. A \$9 billion balance remains outstanding on the DWR bonds, 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 \$2.1 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 PG&E's weighted cost of capital which was higher than the cost of debt. The Energy Recovery Bonds are due to expire in 2012.

**Table 5.2 2009 Bond Expenses (000)**

	PG&E	SCE	SDG&E
DWR Bond Charges	\$406,569	\$426,780	\$88,238
Rate Reduction Bonds	\$0	\$0	\$0
Energy Recovery Bonds	\$437,282	\$0	\$0
<b>Total</b>	<b>\$843,851</b>	<b>\$426,780</b>	<b>\$88,238</b>

## **Fees, Incentives and Voluntary Programs:**

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. An example is the Risk/Reward Incentive Mechanism (RRIM) for promoting energy efficiency and the Performance Based Ratemaking (PBR) incentives. Voluntary programs such as the Climate Smart program are non-mandatory programs that the utilities offer to customers who want to do more for the environment than the various mandated programs. In total, this entire category of expenses accounted for 0.3% of the Revenue Requirement in 2009, a total of \$123 million.

**Table 5.3 2009 Regulatory Fees (000)**

	PG&E	SCE	SDG&E
<b>Fees</b>			
CPUC fee*	\$21,147	\$0	\$0
Environmental Enhancement	\$10,103	\$0	\$0
Research and Development and Deployment	\$34,436	\$28,244	\$6,100
Nuclear Decommissioning	\$25,697	\$45,929	\$9,350
Spent Nuclear Fuel	\$0	\$5,212	\$948
DOE D&D Fees	\$15,362	\$0	\$0
Nuclear Decommissioning, Franchise Fees and Uncollectibles	\$0	\$578	\$110
<b>Incentives</b>			
Annual Earnings Assessment Proceeding (AEAP) Incentive	\$0	\$24,700	\$0
Non-Utility Affiliate Credit/ Reduced Capital Recovery Amount (RCRA) Offset	\$0	(\$11,132)	\$0
Performance-Based Regulations	\$0	(\$103,106)	\$0
Franchise Fee & Uncollectible Surcharge	\$0	\$5,771	\$0
<b>Voluntary Programs</b>			
Climate Smart	\$4,293	\$0	\$0
<b>Total</b>	<b>\$111,037</b>	<b>(\$3,805)</b>	<b>\$16,508</b>

\* SCE and SDG&E do not include the CPUC fee in the consolidated Revenue Requirement, and instead collect the fee as a separate charge on the utility bill.

### **Definition of Fees**

- **CPUC Fee:** This is the annual fee to recover the CPUC's operating costs.

- **Franchise Fees:** Fees paid by a privately owned utility to cities and counties for the right to use or occupy public streets, roads, and for permission to provide service in their jurisdictions. These fees are then redistributed to the cities and counties.
- **Uncollectibles:** Includes accounts receivable that have defaulted or cannot be collected
- **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.
- **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 competent federal or state authorities.
- **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.
- **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.

#### Incentives

- **Annual Earnings Assessment Proceeding (AEAP) Incentive:** Incentives received by a utility, based on a portion of the net present value of the savings achieved by ratepayers participating in energy efficiency programs.
- **Performance-Based Regulation Incentive:** The mechanism enables the investor owned utilities to earn rewards on energy efficiency programs in amounts comparable to what the companies would otherwise earn through supply side investments. The decisions establish a performance standard for the utilities, under which the utilities earn incentives if their energy efficiency program portfolios achieve certain quantitative energy efficiency savings goals.
- **Non-Utility Affiliate Credit/ Reduced Capital Recovery Amount (RCRA) Offset:** Mechanism that initially provided for additional annual nuclear depreciation expense of \$75 million, which was offset by suspending annual distribution depreciation expense of \$75 million, in accordance with D.94-05-068. Requirement was modified by D.99-10-057, and D.02-04-016.

#### Voluntary Programs

- **Climate Smart: (PG&E only)** A voluntary program where PG&E customers can elect to pay a monthly premium to offset greenhouse gas emissions associated with energy usage. Program administrative and marketing costs are recovered through distribution rates.

## VI. Natural Gas Utility Ratepayer Costs

The CPUC determines the reasonableness of operational costs, cost allocation among customer classes and rate design for Pacific Gas and Electric Company (PG&E) Southern California Gas Company (SoCal Gas) and San Diego Gas and Electric Company (SDG&E). Unlike electricity, the CPUC does not set an annual authorized revenue requirement for gas 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). Total natural gas utility costs in 2009 were much lower than in recent past years due to a significant decrease in the price of natural gas.

**Table 6.1 2009 Gas Revenue Requirement Summary (000)**

	PG&E	SoCalGas	SDG&E
Core Procurement	\$2,020,976	\$1,441,099	\$185,434
Transportation	\$1,488,501	\$1,782,220	\$285,920
Public Purpose Programs	\$222,589	\$271,411	\$37,482
<b>TOTALS</b>	<b>\$ 3,732,066</b>	<b>\$ 3,494,730</b>	<b>\$ 508,836</b>

### Core Gas Procurement

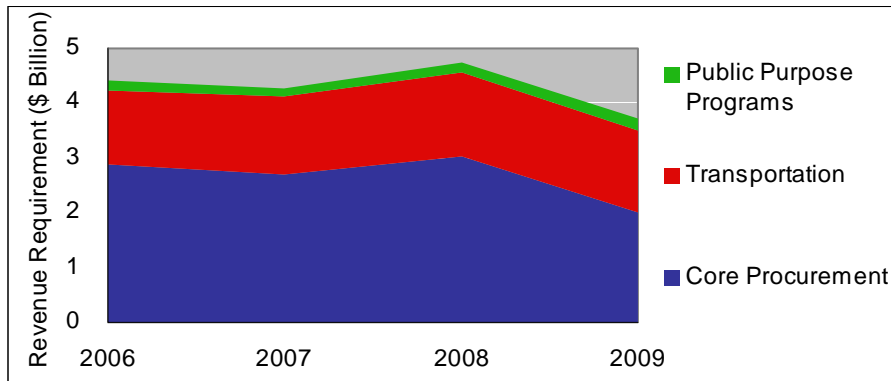
The major natural gas utilities recover procurement costs as a component called the gas procurement rate. The gas procurement rate is changed every month to reflect the most current price of natural gas. The procurement rates are changed routinely through utility advice letter filings with the CPUC. Core gas procurement costs in 2009 were low relative to recent past years. Although core gas customers--primarily residential and small commercial customers--in California have the option to choose a non-utility natural gas supplier, natural gas utilities in California provide procurement service for over 98% of core customers. 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, and other costs. The major component of core procurement costs is the cost of the commodity itself.

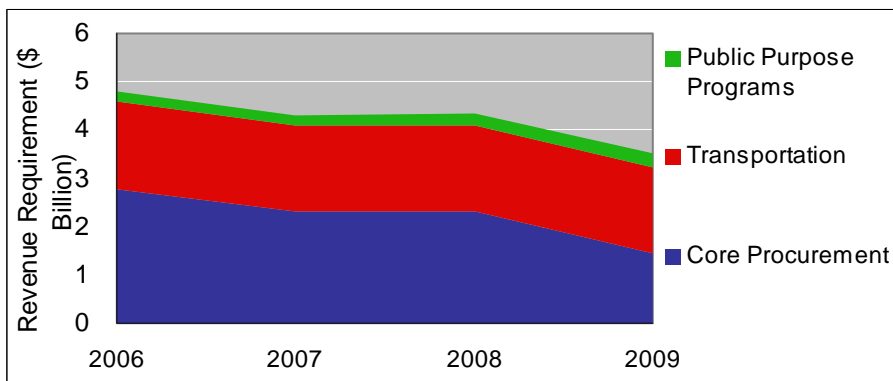
Due to a significant decrease in the price of natural gas since mid-2008, the state's natural gas utilities' procurement costs have drastically fallen since mid-2008. As the following table shows, natural gas utility procurement costs are at their lowest level in recent years. This has resulted in the lowest total core gas procurement rates in at least the last five years.

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

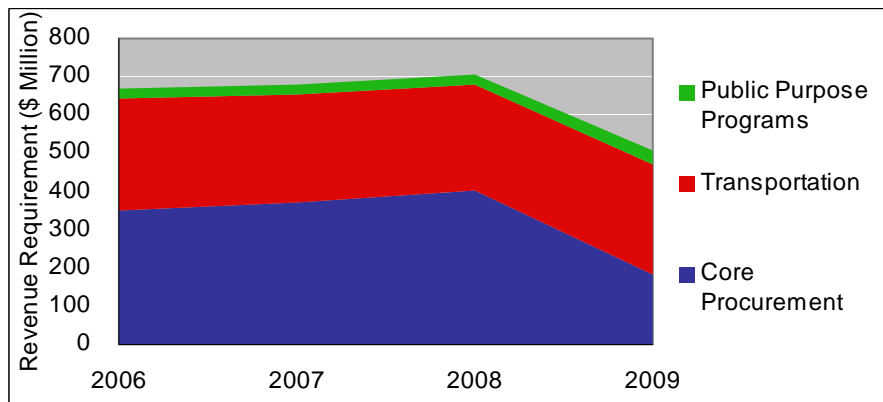
**Figure 6.2 Trends in PG&E Gas Utility Revenue Requirements**



**Figure 6.3 Trends in SoCalGas Gas Utility Revenue Requirements**



**Figure 6.4 Trends in SDG&E Gas Utility Revenue Requirements**



## 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. The bulk of these revenue requirements are primarily determined by the CPUC in two types of major proceedings: general rate cases for PG&E, SoCalGas and SDG&E, and 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 only 4% from 2006 through 2009. This increase seems to have occurred almost entirely due to increases authorized for PG&E natural gas distribution costs.

These costs are mainly recovered by the utilities through end-use transportation rates, backbone transmission rates (for PG&E) or “firm access rights” rates (for SoCalGas), and storage rates. Such rates are generally changed annually, in accordance with previous CPUC decisions which have adopted revenue requirements, cost allocation and rate design.

PG&E backbone transmission service, SoCalGas firm access rights service and both utilities’ storage service are optional services for noncore customers. If a noncore customer opts not to take those services, they would not be charged for those services. Such customers typically take delivery of supplies at the utility “citygate” from a marketer (who may be paying for these services), and only pay the utility transportation rate.

**Figure 6.5 Historic Gas Utility Revenue Requirement Summary (000)**

	2006	2007	2008	2009
Core Procurement	\$6,011,301	\$5,410,391	\$5,753,175	\$3,647,509
Transportation	\$3,441,321	\$3,464,554	\$3,595,241	\$3,556,641
Public Purpose Programs	\$443,860	\$375,358	\$429,897	\$531,482
<b>Total</b>	<b>\$9,898,488</b>	<b>\$9,252,310</b>	<b>\$9,780,321</b>	<b>\$7,735,632</b>

## **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 in recent years, but are a small part of total costs.

Costs authorized by the CPUC for natural gas PPPs have increased by 23% overall since 2006. Gas PPP costs have increased primarily due to significant increases for energy efficiency, low-income energy efficiency, and natural gas research and development programs. These increases more than offset decreases in the CARE subsidy. With these increases, gas PPP costs were about 7% of total utility costs in 2009.

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.

## Appendix A: AB 67 Table—Annual Electric Revenue Requirement

	Federal/State Mandate	CPUC Mandate	PG&E	SCE	SDG&E
<b>Generation Total</b>			<b>5,521,821</b>	<b>5,244,444</b>	<b>884,386</b>
Qualifying Facilities	Federal PURPA, 1978; PUC Section 454.5(d)(3)	CPUC Decisions	1,387,873	2,140,916	109,432
General Rate Case Revenues		CPUC Decisions	1,219,636	1,172,663	187,998
Renewable Portfolio Standard*	PUC Section 454.5(d)(3)	CPUC Decisions	510,078	0	161,751
Other Utility Fuel & Purchased Power	PUC Section 454.5(d)(3)	CPUC Decisions	2,388,938	1,930,865	425,205
Other		CPUC Decisions, Resolutions	15,296	0	0
<b>Transmission Total</b>			<b>771,022</b>	<b>510,164</b>	<b>259,053</b>
Reliability Services	FERC Order 459		35,584	(14,595)	10,219
Transmission Access Charge	FERC		(5,265)	77,326	(29,989)
Transmission Owner Rate Case Revenues	FERC		830,751	447,433	293,027
Other - FERC Rate Case Revenues	FERC		(90,048)	0	(14,204)
<b>Distribution Total</b>			<b>3,659,068</b>	<b>3,830,973</b>	<b>996,458</b>
Advanced Metering Infrastructure		Report	0	0	40,315
Smart Meter			90,954	97,332	0
Self-Generation Incentive Program	PUC Section 379.6(a)	CPUC Decisions	30,186	28,000	10,035
California Solar Initiative <sup>†</sup>		CPUC Decisions	141,436	0	0
Demand Response Program	PUC Section 740.10, 740.7, 740.9, 740.11	CPUC Decisions	95,266	47,803	15,390
Catastrophic Events	PUC Section 454.9(a)	CPUC Decisions	12,586	7,691	0
General Rate Case Revenues		CPUC Decisions	3,207,111	3,732,404	920,351
Hazardous Substance Mechanism		CPUC Decisions	6,451	7,282	242
AEAP Intentives		CPUC Decisions	0	24,700	0
Low Emission Vehicle Program	PUC Section 740.3 & 740.8	CPUC Decisions, Resolutions	0	0	315
CPUC Fee	PUC Section 431	CPUC Resolution M-4816	21,147	0	0
Climate Smart			4,293	0	0
Other		CPUC Decisions, Resolutions	14,653	(11,132)	0
PBR Sharing Mechanism		CPUC Decisions, Resolutions	0	(103,106)	0
Customer Service & Safety Awards/Penalties		CPUC Decisions, Resolutions	34,986	0	9,810
<b>Nuclear Decommissioning</b>	PUC Sections 8321-8330, 10 CFR 50.33, 50.75	CPUC Decisions	<b>23,846</b>	<b>51,348</b>	<b>10,298</b>
<b>Public Purpose Programs Total</b>			<b>157,190</b>	<b>207,858</b>	<b>28,247</b>
Energy Efficiency, PUCode 399.8 <sup>†</sup>	PUC Section 399.8	CPUC Decisions, E-3792	(149,976)	99,076	(4,800)
RD&D PUCode 399.8	PUC Section 399.8	CPUC Resolution E-3792	34,436	28,244	6,805
Renewables, PUCode 399.8 <sup>†</sup>	PUC Section 399.8	CPUC Resolution E-3792	36,009	(161,670)	(39,766)
Energy Efficiency, non-PUCode 399.8		CPUC Decisions	203,706	155,586	51,338
Low Income Energy Efficiency	PUC Sections 739.1, 739.2, 2790	CPUC Decisions, Resolutions	68,308	60,242	12,527
CARE Adm., CARE amortized in rates <sup>†</sup>	PUC Section 739.1, 739.2	CPUC Decisions	(35,293)	26,379	2,143
<b>DWR Power Charge Revenues</b>	ABIX, Water Code, Division 27	CPUC Decisions	<b>1,593,664</b>	<b>1,379,923</b>	<b>542,715</b>
<b>DWR Bond Charge Revenues</b>	ABIX, Water Code, Division 27	CPUC Decisions	<b>406,569</b>	<b>426,780</b>	<b>88,238</b>
<b>AB1890 Rate Reduction Bonds</b>	AB 1890, PUC Section 368(a), 840-847	CPUC Decisions, Resolutions	<b>(14,194)</b>	<b>0</b>	<b>0</b>
<b>Ongoing Competition Transition Charge</b>	AB 57, PUC Section 367(a) & 369	CPUC Decisions	<b>426,566</b>	<b>106,365</b>	<b>43,895</b>
<b>Energy Recovery Bonds (PG&amp;E only)</b>	SB 772, PUC Section 848-848.7	CPUC Decisions, Resolutions	<b>202,777</b>	<b>0</b>	<b>0</b>
<b>Franchise Fee Surcharge</b>	PUC Sections 6350-6354, 6231	CPUC Decisions	<b>0</b>	<b>5,940</b>	<b>3,370</b>
<b>Electric Total</b>			<b>12,748,329</b>	<b>11,763,795</b>	<b>2,856,660</b>

\*SCE incurred no above-market RPS expenses in 2009 because all of its RPS-eligible generation was procured through QF contracts.

<sup>†</sup>This table shows Revenue Requirements collected in rates, after balancing account adjustments. Certain program areas incurred expenses but did not request funds to be collected in 2009 rates, due to overcollections in previous years. For further explanation, see page 4 and 22.

## Appendix A: AB 67 Table—Annual Gas Revenue Requirement

	Federal/State Mandate	CPUC Mandate	PG&E	SDG&E	SoCalGas
<b>Core Procurement Total</b>			<b>2,020,976</b>	<b>185,434</b>	<b>1,441,099</b>
Core Gas Supply Portfolio		CPUC Decisions	1,583,614	183,234	1,393,951
Other		CPUC Decisions	313,080		
10/20 Winter Gas Savings		CPUC Resolutions	38,886		
Core Gas Hedging		Report	77,019		35,100
Incentive Mechanism		Report	8,377	2,200	12,048
<b>Transportation Total</b>			<b>1,488,501</b>	<b>285,920</b>	<b>1,782,220</b>
Distribution		CPUC Decisions	1,045,030	261,814	1,735,779
Transmission		CPUC Decisions	332,131		
Advanced Metering Infrastructure		Report	56,767	6	
Smart Meter			6,120	9,914	
Self Generation Incentive Program (SGIP)	PUC Section 379.6 (a)	CPUC Decisions		755	8,135
Climate Smart			1,821		
California Solar Initiative (CSI)		CPUC Decisions		0	
Annual Earning Assessment (AEAP)		CPUC Decisions	6,893	0	
Low Emission Vehicle (LEV)	PUC Section 740.3 & 740.8	CPUC Decisions	0	2,672	37,398
Hazardous Substance Mechanism (HSM)		CPUC Decisions	14,890	492	6,073
Performance Based Regulation (PBR)		CPUC Decisions, Resolutions		0	(24,096)
Customer Service & Safety Performance Indicator		CPUC Decisions, Resolutions		552	2,000
Non Public Interest Research, Dvlp & Demo (RD&D)		CPUC Decisions			10,000
Core Pricing Flexibility Program		CPUC Decisions			255
Non core competitive load growth program		CPUC Decisions			574
Catastrophic Event Memo Acct (CEMA)	PUC Section 454.9 (a), Res E-3238	CPUC Decisions, Resolutions	0		
Z-Factor		CPUC Decisions			
Other Balancing Accts Balances		Report	(6,759)	6,122	(50,641)
CPUC Fee	PUC Section 431	Resolution M-4816	4,794		
Franchise Fees & Uncollectibles	PUC Section 6231	CPUC Decisions	1,596		
Franchise Fee Surcharge (G-SUR)	PUC Sections 6350-6354	CPUC Resolutions	25,218	3,593	59,743
<b>Public Purpose Programs</b>			<b>222,589</b>	<b>37,482</b>	<b>271,411</b>
Energy Efficiency (EE) Programs	PUC Sections 399.8, 890-900	CPUC Decisions	69,539	11,527	86,437
Low Income Energy Efficiency (LIEE)	PUC Sections 739.1, 890-900, 2790	CPUC Decisions	43,205	9,912	48,572
Public Interest RD&D and State Board of Equalization (BOE)	PUC Sections 740, 890-900	CPUC Decisions	10,169	1,361	13,185
California Alternate Rates for Energy (CARE) Program	PUC Sections 739.1 & .2, 890-900	CPUC Decisions	99,676	14,682	123,217
<b>GAS TOTAL</b>			<b>3,732,066</b>	<b>508,836</b>	<b>3,494,730</b>