Revised 1997 Retail Electricity Price Forecast

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CALIFORNIA ENERGY COMMISSION ELECTRICITY ANALYSIS OFFICE
REVISED 1997 RETAIL ELECTRICITY PRICE FORECAST

Introduction

The Electricity Analysis Office of the California Energy Commission (CEC) develops retail price forecasts for use as an input into the Commission's demand forecasts. (The full forecast is shown in Tables 3 through 7.) We develop forecasts for Southern California Edison[1] (Edison), Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), the Los Angeles Department of Water and Power (LADWP), the Sacramento Municipal Utility District (SMUD), and the combined service areas of Burbank-Glendale-Pasadena (BGP). This Revised Retail Electricity Price Forecast takes into account the effects of recent regulatory and legislative actions on the electricity industry.

We develop these price forecasts for the internal use of Energy Commission Staff. The California Energy Commission does not set retail prices for any of the utilities for which it develops forecasts. These forecasts of average system and sector retail prices are used in this Commission’s Demand Forecasts. Other uses of these price forecasts may not be appropriate. Some of the assumptions underlying these forecasts are speculative and may not necessarily be realized. Unforeseen economic or political events will have a major impact on actual retail prices. As such, we cannot guarantee the future accuracy of this forecast.

The Restructured Environment

As a result of Assembly Bill 1890 (AB 1890) and California Public Utilities Commission (CPUC) decisions, California’s investor owned utilities (IOUs) and their customers will undergo a multi-year transition to a more competitive market for electricity. This transition period began in 1997 as IOU customer rates were frozen and the IOUs began to collect funds to recover their transition costs in interim transition cost balancing accounts. This transition period will end when the IOUs have fully recovered their generation-related transition costs or by March 31, 2002, whichever is earlier. Transition costs are utility costs that would not be recoverable in a competitive market for electricity. Generation-related transition costs are the remaining capital costs of utility-owned generation plant. In this forecast, we have assumed that the transition period (and the utilities’ collection of generation-related transition costs) will end on the last day of 2001.

Major features of IOU prices in this transition period are the ten percent retail price reduction for residential and small commercial customers (with demand less than 20 kW), a retail price freeze for larger commercial and industrial customers, rate reduction bond issuance and repayment by

1 The Edison forecast is for the Edison service area which includes Edison and the six resale cities of Anaheim, Azusa, Banning, Colton, Riverside and Vernon. They are called the resale cities because they buy power from Southern California Edison for resale to their customers.

residential and small commercial customers, a competitive transition cost (CTC) payment [2] and unbundling of retail electric bills. On January 1, 1998, residential and small commercial customers receive a 10 percent retail price reduction in the form of a bill credit. This bill credit will continue to apply through the year 2001. The reduction for residential and small commercial customers is financed by the issuance of rate reduction bonds that were sold in December 1997.

Residential and small commercial customers are obligated to make the bond payments from January 1998 to December 2007. The retail electric rates of larger commercial, industrial and agricultural customers that remain IOU customers are frozen for the duration of the transition period. Utilities recover their transition costs from revenues received under the rate freeze. Nearly all IOU customers that remain connected to the transmission or distribution system or continue to use electricity will make CTC payments.

Starting in June 1998, IOU retail electric bills will be unbundled to show the amounts paid for each of the components of electricity service. The major components are charges for the energy market price, transmission service, distribution service, the public purpose program charge, nuclear decommissioning, fixed transition amount (or trust transfer amount) and the competition transition charge. The energy market price will show the average market price of electricity bought from the newly formed wholesale electricity market. Transmission and distribution service charges are the regulated cost of transmitting and distributing the electricity purchased to consumers. The public purpose program charge recovers the cost of mandated state programs, such as low income discounts (California Alternate Rates for Energy Surcharges). Nuclear decommissioning costs are collected to fund a reserve against the costs of the eventual retirement of nuclear power plants. The fixed transition amount, or trust transfer amount, is the payment for rate reduction bonds which is an obligation of residential and small commercial customers who received the 10 percent reduction in retail price. Finally, the CTC is calculated as the residual after all other charges have been deducted from the retail price.

After the transition period, customers will pay market prices for the energy portion of the service provided to them. Transmission and distribution costs, public purpose programs costs, and nuclear decommissioning payments will continue to be regulated. The CTC payment will continue after the transition period, but will significantly decrease. After December 31, 2001, all customers continue to pay a residual transition cost charge that depends primarily on the level of above-market payments to Qualifying Facilities. A small portion of the transition cost charge will be for utility employee transition costs and the Independent System Operator/Power Exchange (ISO/PX) startup costs. Residential and small commercial customers also continue to pay for the rate reduction bonds until the end of 2007.

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[2] The competitive transition charge includes payments for the utility's generation-related transition costs, as well as for above-market purchased power payments, ISO/PX startup costs and employee transition costs.

Municipal utilities are not required to participate in the restructuring of the electricity industry defined by AB 1890. However, municipal utilities are still under pressure from their current customers to provide competitive prices or direct access to third party providers. AB 1890 provides an incentive for municipal utilities to participate in restructuring. New sections of Public Utilities Code (PU Code) added by AB 1890 authorizes municipal utilities that allow direct access to collect transition costs from its customers.[3] In this way, municipal utilities are afforded the same privilege as IOUs in collection of previously incurred costs.

In anticipation of the threat of competition, municipal utilities have begun to set aside funds to recover their anticipated transition costs. These funds become available either by instituting rate freezes as revenue requirements fall or by special rate increases designed to recover transition costs. For several years, SMUD has had an overall rate freeze, while it has been setting aside funds to recover its investment in nuclear power generation and conservation and load management programs. Recently, the city of Pasadena instituted a special surcharge of 1.37 cents per kWh to recover its estimated transition costs. The proceeds are to be deposited in a reserve account until Pasadena's transition costs are completely recovered. This surcharge will last until Pasadena's transition costs are fully recovered or until June 30, 2002, whichever occurs first. For purposes of this forecast, we assume that municipal utilities will participate in the competitive market for electricity at the beginning of 2002.

Differences from Previous Forecasts

There are significant differences in the forecast methods used in this forecast compared to previous forecasts, as well as in its results. In previous forecasts, we used the financial module of the Elfin model.[4] In this forecast, we did not use the Elfin financial module as it is not able to forecast retail prices for individual classes, nor can it deal with the various aspects of the retail price cap. In past forecasts, we would use the financial model to calculate the revenue requirement, then used the sales forecast to calculate an average system cost. All sector retail prices would then increase from their actual levels at the rate of change of the average system cost. In this forecast, we reversed the process. Since retail price levels are known for the transition period, we used forecast sales to calculate revenues by sector and added up to get total sales revenue. After the transition period, we calculated the regulated components of retail prices for each sector separately and added the energy market price to come up with the total retail price for each sector.

All historical data for the LADWP, BGP and the resale cities[5] were converted from fiscal year to calendar year, since our current source of historical data for these utilities is the Energy Information Administration (EIA) which collects data on a calendar year basis. The forecasts for all utilities are considerably lower than those of the ER 96 Preliminary Price Forecast done four

[3] See Public Utilities Code, Sections 9602 and 9603.

[4] The Elfin model consists of two separate modules: a financial module and a production cost simulation module. The financial module calculates the traditional revenue requirements of a utility using both historical and forecasted financial data. The production cost module calculates the operating costs (fuel and operations and maintenance expenses) of a utility electricity generating system.

[5] The resale cities are Anaheim, Azusa, Banning, Colton, Riverside and Vernon. See footnote 1.

years ago. The forecasts for the municipal utilities show smaller changes, especially in the longer term. We attribute these differences to a number of factors. First, in the past few years, the IOUs and some municipal utilities have been reducing costs in anticipation of competition in electricity markets. This has led to lower forecasts of operating and maintenance (O&M) expenses. Second, as generation-related transition costs are recovered in the transition period, the utilities need only charge the energy market price for electricity delivered. This leads to much lower retail prices as market prices are significantly lower than the utility's current cost of generation. In Table 1, we show the differences between the current forecast and the ER 96 Forecast for the years 1998, 2002, 2007, 2012 and 2015.

Table 1
Comparison of 1997 Revised and ER 96 Preliminary Price Forecasts
Average System Rates for Selected Years
(in 1998 cents per kWh)

Year	PG&E			Edison		
	1997	ER 96	% Change	1997	ER 96	% Change
1998	9.4	10.1	-6.9%	9.4	10.2	-7.1%
2002	6.7	9.5	-29.6%	7.0	9.0	-22.0%
2007	6.4	9.2	-30.0%	6.5	8.5	-22.9%
2012	6.0	9.2	-34.6%	6.1	8.8	-31.2%
2015	6.0	9.3	-35.3%	6.1	9.0	-32.8%
Year	SDG&E			LADWP		
	1997	ER 96	% Change	1997	ER 96	% Change
1998	9.1	10.0	-9.1%	9.1	9.3	-2.1%
2002	7.2	9.4	-23.0%	6.2	8.9	-30.0%
2007	7.1	8.9	-20.0%	6.3	8.5	-25.8%
2012	7.0	9.1	-22.4%	6.4	8.5	-24.2%
2015	7.1	9.1	-22.0%	6.5	8.3	-21.8%
Year	SMUD			BGP		
	1997	ER 96	% Change	1997	ER 96	% Change
1998	7.7	8.6	-10.2%	10.0	9.6	4.9%
2002	5.6	8.6	-34.5%	7.4	9.2	-19.5%
2007	5.7	7.9	-28.0%	7.3	8.8	-17.4%
2012	5.8	7.7	-24.2%	7.4	8.7	-15.8%
2015	5.9	7.3	-19.2%	7.4	8.6	-13.2%

Forecast Assumptions

The forecast for the investor owned utilities (IOUs) relies primarily on the policy direction supplied in decisions by the CPUC and the Legislature in AB 1890. Retail prices were frozen in

1997 at their 1996 levels.[6] On January 1, 1998, residential and small commercial customers received a 10 percent retail price reduction, while the prices of larger commercial and industrial customers remained frozen. On January 1, 2002, all customers will begin to pay market prices for the energy portion of their retail price. PU Code Section 330 (a) added by AB 1890 declares the California Legislature's intent that residential and small commercial customers shall receive a minimum retail price reduction of 20 percent from their 1996 levels. This reduction is to be measured on the portion of retail price excluding the portions that go to pay for the market price of energy and rate reduction bonds. We interpret this as an additional ten percent reduction in the transmission and distribution (T&D) component of the retail price.[7] (However, this assumption is not critical to our forecast.) The T&D, public purpose program charge and nuclear decommissioning components of retail prices for all customers is assumed to increase at the rate of inflation after 2001.

We assume that the retail price cap will continue in force until December 31, 2001. We are aware of the possibility that the IOUs may fully recover their projected transition costs before that date, and that the cap may end early.

The forecast for municipal utilities (including the resale cities) assumes that retail prices will be frozen at their 1996 levels from 1997 to 2001. Of the municipal utilities, LADWP and SMUD have frozen retail prices. However, we believe that the other municipals will be forced to freeze or cap retail prices in the near term in order to pay for any above-market costs of generation or purchased power contracts. There may also be some reallocation of costs from large commercial and industrial customers to residential and small commercial customers in order to more closely align rates with actual costs of service for different customer classes. We do not have sufficient information to predict changes in retail prices due to possible reallocations. We assume that customers of municipal utilities will begin to participate in the market for electricity beginning in January 1, 2002.

The energy market price forecast used was developed by CEC Staff in "Interim Staff Market Clearing Price Forecast for the California Energy Market," December 10, 1997. The market price forecast is an energy only price and does not include the costs of ancillary service payments, must-run contracts, or transmission fees. The market price forecast is shown in Appendix A. An ISO/PX operations charge of 0.1 cents per kWh that increases with the rate of inflation was added to the energy market price.

We used information from IOU filings at the CPUC to allocate current rates to the energy, transmission, distribution, public purpose program, nuclear decommissioning, rate reduction bond payment, and CTC components. When information was not available, we made some

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[6] Although AB 1890 calls for retail prices to be frozen at their June 1996 levels, we assume that retail prices are frozen at the average retail price for 1996. This causes small differences between what the IOUs might report as the frozen retail price level for 1997 and what we show as the forecast for 1997.

[7] The exact language of Section 330 (a) is:

> It is the intent of the Legislature that a cumulative rate reduction of at least 20 percent be achieved not later than April 1, 2002, for residential and small commercial customers, from the rates in effect on June 10, 1996. In determining that the April 1, 2002, rate reduction has been met, the commission shall exclude the costs of the competitively procured electricity and the costs associated with the rate reduction bonds, as defined in Section 840.

simplifying assumptions. These assumptions are critical to the forecast. The larger the electricity portion currently embedded in rates, the greater the proportion of the retail price that will be subject to the electricity market price after 2002 and, the greater the reduction in nominal and real rates after 2002. The allocations used are shown in Table 2.

Table 2
Proportion of Rate Allocated to Energy/Generation and T&D
(in percent)

	Residential		Commercial		Industrial	
	Energy/ Generation	T&D	Energy/ Generation	T&D	Energy/ Generation	T&D
PG&E, Edison	60	40	66	34	76	24
SDG&E	41	59	50	50	65	35
LADWP, SMUD, BGP	55	45	65	35	75	25

Notes: PG&E's allocations are from their unbundling application, January 1997, pp. srh 10, 11.
SDG&E's allocations are from their unbundling application, Dec. 6, 1996, pp. CTC-Tables V-1, V-2
Edison's allocations are set equal to PG&E's.
Proportions for LADWP, SMUD and BGP are placeholders until better information is obtained.

The 1997 Preliminary GDP Deflator forecast was used as the measure of inflation. This forecast is shown in Appendix B. The natural gas price forecast used in developing the energy market price forecast is shown in Appendix C.

These forecasts are dependent on when rate-making decisions are made and subject to future uncertainties. We have listed some of the major uncertainties below. For example, the energy market price forecast is an average for the entire year and will not reflect differences in load factors among the different sectors. Residential and small commercial customers are more likely to use a higher proportion of energy during peak times and would pay higher market prices at those times. Our forecast does not take this into account.

Major Uncertainties

Throughout the text, we have pointed out several major uncertainties. First, and foremost, the greatest uncertainty surrounds the energy market price. The critical assumptions underlying the energy market price are outlined in Staff's Report.[8] These include the CEC's natural gas price forecast, load and load shape forecasts, O&M expense forecasts, and ISO/PX bidding protocols. In addition, our energy market price forecast includes an ISO/PX charge, but does not include costs for ancillary service payments, must-run contracts, or transmission fees.

[8] See "Interim Staff Market Clearing Price Forecast for the California Energy Market," December 10, 1997, pp. 6-10.

Second, we have not accounted for demand elasticities in developing our forecast. Our current forecast is lower than the previous forecast. Lower prices may lead to some increase in demand by customers which might change the relative proportions of sales to the different sectors and result in changes in the average system rate. For example, lower residential rates might lead to increased residential consumption and increased residential sales revenue. Since residential rates are higher than the system average, the higher demand would lead to higher system average rates.

Third, we do not have current information on the relative proportions of electricity, transmission and distribution costs in municipal retail prices. To the extent that the T&D costs are a greater proportion than we assumed, our forecast of retail municipal retail prices would be higher.

Fourth, we have not accounted for the possibility that the IOUs will fully recover their generation transition costs prior to December 31, 2001. If they do, it is possible that they and the CPUC may continue the retail price cap to accelerate recovery of other transition costs. It is also possible that retail price cap will end and retail prices will decline greatly as the electricity component falls to the electricity market price.

Fifth, our forecast does not account for differences in sector usage patterns. As we pointed out earlier, the market price forecast is an average for the entire year and will not reflect differences in load factors among the different rate classes. Residential and small commercial customers are more likely to use a higher proportion of energy during peak times and would pay higher market prices for energy at those times resulting in higher retail rates.

Finally, we have not accounted for pending applications before the CPUC that would affect the level of base rates. For example, PG&E has requested a $693 million increase in base rates effective January 1, 1999. If granted this increase would not affect the level of retail prices before 2002, since those have been mandated by AB 1890. However, this increase in base rates would affect the recovery of PG&E's generation-related transition costs and would prevent the retail price cap from ending before December 31, 2001.

Forecast Results

The results of our forecast are shown in Tables 3 through 7 below.

Table 3
Revised 1997 Price Forecast for Baseline Demand Trends
Constant Dollar Average System Rates (1998$)
in cents per kWh
Historical 1977 to 1996
Forecast 1997 to 2017

Year	PG&E	Edison	SDG&E	LADWP	SMUD	BGP
1977	9.8	8.8	11.5	9.1	4.5	11.1
1978	8.3	9.3	11.2	9.5	4.6	11.4
1979	8.4	9.1	12.2	9.9	4.4	13.2
1980	9.4	11.9	16.0	10.8	4.6	12.4
1981	10.8	11.5	16.3	10.9	4.7	11.0
1982	10.4	12.2	18.5	10.1	5.3	11.4
1983	10.2	11.8	18.4	9.2	5.7	10.8
1984	12.0	11.7	17.9	9.2	5.7	10.7
1985	12.9	11.7	18.8	9.6	6.5	10.3
1986	12.5	11.8	16.3	9.6	7.7	9.9
1987	10.6	11.4	14.1	9.7	9.0	10.3
1988	10.6	11.5	12.8	10.1	9.4	10.9
1989	11.3	11.9	11.9	10.4	9.4	11.1
1990	11.4	11.8	11.0	10.4	9.6	10.9
1991	11.7	12.1	10.8	9.7	9.2	10.5
1992	12.0	12.1	10.6	9.9	8.9	10.6
1993	11.8	11.4	10.7	10.2	8.1	10.7
1994	11.7	11.4	10.3	10.2	8.3	10.9
1995	10.5	11.3	10.0	9.8	8.2	10.5
1996	10.4	10.4	9.9	9.5	8.1	10.3
1997	10.2	10.2	10.0	9.3	7.9	9.8
1998	9.4	9.4	9.1	9.1	7.7	10.0
1999	9.2	9.2	8.9	8.9	7.5	9.8
2000	9.0	9.0	8.6	8.6	7.3	9.5
2001	8.7	8.7	8.4	8.4	7.1	9.3
2002	6.7	7.0	7.2	6.2	5.6	7.4
2003	6.6	6.9	7.2	6.2	5.6	7.2
2004	6.6	6.8	7.2	6.3	5.7	7.2
2005	6.5	6.7	7.2	6.3	5.7	7.2
2006	6.5	6.6	7.2	6.3	5.7	7.2
2007	6.4	6.5	7.1	6.3	5.7	7.3
2008	6.1	6.2	7.0	6.3	5.7	7.3
2009	6.1	6.1	7.0	6.3	5.8	7.3
2010	6.1	6.1	7.0	6.4	5.8	7.3
2011	6.1	6.1	7.1	6.4	5.8	7.3
2012	6.0	6.1	7.0	6.4	5.8	7.4
2013	6.0	6.1	7.1	6.4	5.9	7.4
2014	6.0	6.1	7.1	6.5	5.9	7.4
2015	6.0	6.1	7.1	6.5	5.9	7.4
2016	6.0	6.1	7.1	6.5	5.9	7.5
2017	6.0	6.1	7.2	6.5	5.9	7.5

Table 4
Revised 1997 Price Forecast for Baseline Demand Trends
Constant Dollar Average Residential Rates (1998$)
in cents per kWh
Historical 1977 to 1996
Forecast 1997 to 2017

Year	PG&E	Edison	SDG&E	LADWP	SMUD	BGP
1977	9.2	10.4	11.7	10.8	4.8	11.3
1978	7.7	10.3	10.8	11.1	4.9	12.4
1979	8.2	9.8	11.5	11.4	4.7	14.2
1980	9.1	11.8	15.1	11.8	5.0	13.2
1981	10.6	11.6	15.5	11.3	5.1	11.8
1982	10.1	12.3	18.4	10.4	5.7	11.5
1983	9.7	11.4	18.4	9.5	6.3	10.9
1984	11.4	11.4	17.2	9.6	6.4	10.8
1985	12.1	11.4	18.0	9.9	7.2	10.5
1986	12.0	11.4	16.0	9.9	8.5	10.1
1987	10.7	11.2	14.6	10.2	10.0	10.6
1988	11.5	12.0	14.3	10.6	10.7	11.1
1989	12.6	12.9	13.8	10.9	10.2	11.1
1990	12.9	13.1	12.8	10.9	10.0	11.0
1991	13.4	13.7	12.4	10.5	9.6	10.5
1992	13.7	13.9	12.2	10.5	9.4	10.6
1993	13.7	13.5	12.3	11.0	8.5	10.6
1994	13.6	13.4	11.6	10.8	8.7	10.7
1995	12.3	13.7	11.3	10.5	8.7	10.3
1996	12.4	12.9	11.3	10.2	8.7	10.0
1997	12.2	12.7	11.1	10.0	8.5	9.8
1998	10.7	11.2	9.7	9.8	8.3	10.0
1999	10.5	10.9	9.5	9.5	8.1	9.8
2000	10.2	10.6	9.2	9.3	7.9	9.5
2001	9.9	10.3	9.0	9.0	7.7	9.3
2002	7.9	8.6	8.5	7.3	6.7	7.4
2003	7.8	8.4	8.4	7.3	6.7	7.2
2004	7.7	8.2	8.4	7.3	6.7	7.2
2005	7.6	8.1	8.3	7.3	6.7	7.2
2006	7.5	7.9	8.2	7.4	6.7	7.2
2007	7.4	7.7	8.2	7.4	6.8	7.3
2008	6.8	7.0	7.7	7.4	6.8	7.3
2009	6.7	6.9	7.7	7.4	6.8	7.3
2010	6.7	6.9	7.8	7.4	6.8	7.3
2011	6.7	6.9	7.8	7.5	6.8	7.3
2012	6.6	6.9	7.8	7.5	6.9	7.4
2013	6.6	6.9	7.8	7.5	6.9	7.4
2014	6.6	6.9	7.9	7.5	6.9	7.4
2015	6.6	6.9	7.9	7.6	7.0	7.4
2016	6.6	6.9	7.9	7.6	7.0	7.5
2017	6.6	6.9	7.9	7.6	6.9	7.5

Table 5
Revised 1997 Price Forecast for Baseline Demand Trends
Constant Dollar Average Commercial Rates (1998$)
in cents per kWh
Historical 1977 to 1996
Forecast 1997 to 2017

Year	PG&E	Edison	SDG&E	LADWP	SMUD	BGP
1977	11.4	9.1	13.1	8.9	5.2	12.5
1978	9.7	9.8	13.0	9.3	5.2	12.6
1979	9.7	9.5	14.0	9.6	3.7	14.5
1980	10.3	12.5	17.5	10.7	4.8	13.6
1981	12.1	12.2	17.5	10.9	4.9	11.8
1982	11.4	12.9	18.5	10.2	4.1	14.3
1983	11.0	12.5	18.2	9.3	5.6	13.4
1984	13.0	12.3	18.4	9.3	5.6	13.5
1985	14.0	12.4	19.4	9.6	6.4	13.1
1986	13.8	12.5	17.5	9.7	7.3	12.4
1987	11.9	12.2	14.7	9.9	8.7	12.9
1988	11.6	12.1	12.7	10.2	9.3	13.7
1989	12.1	12.4	11.4	10.4	9.1	13.7
1990	12.2	12.2	10.7	10.5	10.5	13.5
1991	12.3	12.4	10.5	9.6	10.3	13.0
1992	12.7	12.3	10.3	9.8	9.7	13.1
1993	12.4	11.5	10.6	10.0	8.9	13.6
1994	12.2	11.4	10.3	10.6	8.8	13.9
1995	11.0	11.1	10.1	9.6	9.0	13.5
1996	10.6	9.9	10.0	9.4	8.6	13.1
1997	10.4	9.7	10.6	9.2	8.4	12.9
1998	9.7	9.3	9.5	9.0	8.2	12.9
1999	9.5	9.1	9.3	8.8	8.0	12.6
2000	9.3	8.8	9.0	8.5	7.8	12.3
2001	9.1	8.6	8.8	8.3	7.6	11.9
2002	6.4	6.5	7.1	6.0	5.8	7.4
2003	6.4	6.4	7.2	6.0	5.8	7.3
2004	6.3	6.4	7.2	6.0	5.8	7.3
2005	6.3	6.3	7.2	6.0	5.8	7.3
2006	6.3	6.2	7.2	6.1	5.9	7.3
2007	6.3	6.2	7.2	6.1	5.9	7.3
2008	6.1	6.0	7.2	6.1	5.9	7.3
2009	6.1	6.0	7.2	6.1	5.9	7.4
2010	6.1	6.0	7.2	6.1	5.9	7.4
2011	6.1	5.9	7.2	6.2	6.0	7.4
2012	6.1	5.9	7.1	6.2	6.0	7.4
2013	6.1	6.0	7.1	6.2	6.0	7.5
2014	6.1	6.0	7.1	6.2	6.0	7.5
2015	6.1	6.0	7.1	6.3	6.1	7.5
2016	6.1	6.0	7.2	6.3	6.1	7.5
2017	6.1	6.0	7.2	6.3	6.0	7.6

Table 6
Revised 1997 Price Forecast for Baseline Demand Trends
Constant Dollar Average Industrial Rates (1998$)
in cents per kWh
Historical 1977 to 1996
Forecast 1997 to 2017

Year	PG&E	Edison	SDG&E	LADWP	SMUD	BGP
1977	8.4	7.1	10.5	7.6	3.2	10.1
1978	7.0	8.0	10.8	8.0	3.2	10.1
1979	7.0	8.1	11.8	8.6	2.3	12.2
1980	8.3	11.3	15.2	9.8	3.3	11.6
1981	9.6	10.9	15.8	10.3	3.3	10.3
1982	9.4	11.6	18.7	9.5	3.9	9.9
1983	9.8	11.3	18.6	8.7	4.2	9.6
1984	11.6	11.2	18.2	8.6	4.2	9.5
1985	12.5	11.2	19.1	9.0	4.8	9.0
1986	11.4	11.1	15.1	9.0	5.7	8.7
1987	8.4	10.6	12.6	9.1	6.9	9.1
1988	7.9	10.0	10.4	9.2	7.4	9.8
1989	8.3	9.8	9.4	9.3	7.9	10.0
1990	8.2	9.2	8.9	8.9	9.0	9.8
1991	8.3	9.2	8.7	8.6	8.7	9.5
1992	8.5	8.8	8.4	8.9	8.4	9.7
1993	8.0	8.0	8.2	9.5	7.6	9.7
1994	7.8	8.0	7.9	9.0	7.8	9.9
1995	6.9	7.8	7.7	8.7	7.6	9.5
1996	6.6	6.9	7.6	8.4	7.4	9.3
1997	6.5	6.8	7.4	8.3	7.3	9.4
1998	6.4	6.6	7.3	8.1	7.1	9.8
1999	6.2	6.4	7.1	7.9	6.9	9.5
2000	6.1	6.3	6.9	7.7	6.7	9.3
2001	5.9	6.1	6.7	7.5	6.6	9.0
2002	4.9	5.3	5.1	4.8	4.6	5.3
2003	4.8	5.3	5.1	4.8	4.6	5.0
2004	4.8	5.2	5.1	4.9	4.6	5.1
2005	4.8	5.1	5.1	4.9	4.7	5.1
2006	4.8	5.0	5.2	4.9	4.7	5.1
2007	4.7	4.9	5.2	4.9	4.7	5.1
2008	4.7	4.8	5.3	4.9	4.7	5.1
2009	4.6	4.7	5.3	4.9	4.7	5.1
2010	4.6	4.7	5.4	5.0	4.8	5.2
2011	4.6	4.7	5.4	5.0	4.8	5.2
2012	4.6	4.6	5.4	5.0	4.8	5.2
2013	4.6	4.7	5.4	5.0	4.8	5.2
2014	4.5	4.6	5.5	5.1	4.9	5.3
2015	4.5	4.6	5.5	5.1	4.9	5.3
2016	4.5	4.6	5.5	5.1	4.9	5.3
2017	4.5	4.6	5.5	5.2	4.9	5.3

Table 7
Revised 1997 Price Forecast for Baseline Demand Trends
Constant Dollar Average Agricultural Rates (1998$)
in cents per kWh
Historical 1977 to 1996
Forecast 1997 to 2017

Year	PG&E	Edison	SDG&E	LADWP	SMUD	BGP
1977	10.1	8.9	11.5	NA	NA	NA
1978	9.4	10.7	12.1	NA	NA	NA
1979	8.9	10.0	12.6	NA	NA	NA
1980	10.6	13.5	17.3	NA	NA	NA
1981	11.3	11.7	16.7	NA	NA	NA
1982	11.1	13.0	19.0	NA	NA	NA
1983	10.9	12.5	18.6	NA	NA	NA
1984	12.2	12.0	17.2	NA	NA	NA
1985	13.6	12.1	18.2	NA	NA	NA
1986	13.2	12.2	15.5	NA	NA	NA
1987	10.4	11.7	12.4	NA	NA	NA
1988	10.2	12.2	11.4	NA	NA	NA
1989	11.6	12.5	9.8	NA	NA	NA
1990	11.3	11.7	9.5	NA	NA	NA
1991	11.6	11.7	9.3	NA	NA	NA
1992	11.7	11.8	9.2	NA	NA	NA
1993	12.8	11.9	9.8	NA	NA	NA
1994	12.0	11.7	9.8	NA	NA	NA
1995	11.5	11.9	9.4	NA	NA	NA
1996	11.4	10.2	9.3	NA	NA	NA
1997	11.2	10.7	9.1	NA	NA	NA
1998	10.9	10.5	8.9	NA	NA	NA
1999	10.7	10.2	8.7	NA	NA	NA
2000	10.4	10.0	8.5	NA	NA	NA
2001	10.1	9.7	8.2	NA	NA	NA
2002	7.9	9.2	7.5	NA	NA	NA
2003	7.8	9.1	7.5	NA	NA	NA
2004	7.8	8.9	7.5	NA	NA	NA
2005	7.8	8.7	7.5	NA	NA	NA
2006	7.8	8.6	7.5	NA	NA	NA
2007	7.7	8.3	7.6	NA	NA	NA
2008	7.7	8.1	7.6	NA	NA	NA
2009	7.7	7.9	7.6	NA	NA	NA
2010	7.6	7.9	7.7	NA	NA	NA
2011	7.6	7.8	7.7	NA	NA	NA
2012	7.6	7.7	7.7	NA	NA	NA
2013	7.6	7.7	7.7	NA	NA	NA
2014	7.6	7.6	7.8	NA	NA	NA
2015	7.5	7.6	7.8	NA	NA	NA
2016	7.5	7.6	7.8	NA	NA	NA
2017	7.6	7.5	7.8	NA	NA	NA

APPENDIX A
Electricity Market Price Forecast

Year	(1998 cents/kWh)
1998	2.8
1999	2.6
2000	2.6
2001	2.6
2002	2.7
2003	2.7
2004	2.8
2005	2.8
2006	2.8
2007	2.8
2008	2.8
2009	2.9
2010	2.9
2011	2.9
2012	2.9
2013	3.0
2014	3.0
2015	3.0
2016	3.0
2017	3.1
Notes: Market price forecast includes a ISO/PX charge of approximately 0.1 cents per kWh.	

Appendix B
GDP Deflator Index Forecast

YEAR	INDEX	PERCENT CHANGE
1970	28.41	
1971	29.89	5.2%
1972	31.17	4.3%
1973	32.94	5.7%
1974	35.79	8.7%
1975	39.22	9.6%
1976	41.43	5.6%
1977	44.03	6.3%
1978	47.40	7.7%
1979	51.41	8.5%
1980	56.12	9.2%
1981	61.30	9.2%
1982	65.18	6.3%
1983	67.92	4.2%
1984	70.60	3.9%
1985	72.92	3.3%
1986	74.88	2.7%
1987	77.22	3.1%
1988	80.06	3.7%
1989	83.42	4.2%
1990	86.98	4.3%
1991	90.48	4.0%
1992	92.96	2.7%
1993	95.38	2.6%
1994	97.56	2.3%
1995	100.00	2.5%
1996	101.96	2.0%
1997	103.91	1.9%
1998	106.31	2.3%
1999	108.95	2.5%
2000	111.90	2.7%
2001	115.08	2.9%
2002	118.43	2.9%
2003	121.99	3.0%
2004	125.88	3.2%
2005	130.15	3.4%
2006	134.67	3.5%
2007	139.42	3.5%
2008	144.39	3.6%
2009	149.53	3.6%
2010	154.83	3.5%
2011	160.40	3.6%
2012	166.11	3.6%
2013	171.98	3.5%
2014	178.13	3.6%
2015	184.58	3.6%
2016	191.31	3.7%
2017	198.30	3.7%
Average 1997-2017		3.3%
Source: 1970 - 2017 DRI TREND25YR0296 FORECAST		

Appendix C
Natural Gas Price Forecast

(in 1998$ per mmbtu)

	PG&E	Edison	Coolwater	SDG&E
1998	2.50	2.58	2.11	2.86
1999	2.21	2.22	2.10	2.45
2000	2.09	2.20	2.12	2.51
2001	2.12	2.13	2.14	2.59
2002	2.14	2.17	2.16	2.63
2003	2.16	2.22	2.18	2.54
2004	2.20	2.27	2.22	2.64
2005	2.22	2.29	2.25	2.61
2006	2.25	2.34	2.28	2.70
2007	2.27	2.38	2.31	2.72
2008	2.30	2.42	2.34	2.75
2009	2.33	2.46	2.36	2.75
2010	2.36	2.51	2.39	2.81
2011	2.40	2.56	2.43	2.87
2012	2.44	2.61	2.46	2.90
2013	2.47	2.68	2.49	2.97
2014	2.50	2.74	2.52	3.02
2015	2.54	2.79	2.55	3.05
Source: Fuels Report 1997 Gas Price Forecast, 11/17/97.				