SB 695 Report To California Public Utility Commission Energy Division
Reporting Entity: Pacific Gas and Electric Company
Year: 2010

I. Introduction

Pursuant to the requirements of Public Utilities Code section 748(b), Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide its initial study and report to the California Public Utilities Commission (CPUC or Commission) on measures PG&E recommends to be undertaken to limit costs and rate increases. This report provides data and forecasts related to PG&E's gas and electric revenue requirements and rates, and is structured to include PG&E's overall rate policies at PG&E; a description of PG&E's current revenue requirement components, a discussion of PG&E's rate components, PG&E's management of its rate components, and a schedule of PG&E's 2010 rate filings (as an appendix).

Last summer PG&E heard from many electricity customers that electricity rates for customers who use the most energy were just too high. In these tough economic times, PG&E knows how important it is for our customers to keep monthly costs to a minimum. PG&E understands that electricity is a fundamental need and PG&E is also working hard to help our customers save.

Last month, PG&E filed a number of actions with the California Public Utilities Commission asking for rate relief for customers in two forms. First, PG&E has requested an overall rate reduction to take effect on June 1. Second, PG&E has asked the CPUC to change the tiered residential rate structure in a way that reduces the costs for our highest use residential customers.

Current state law mandates that electric utilities in California must charge more per unit of electricity as a household's use increases. Under the tiered-rate system, electricity use is divided into tiers, with higher prices for each higher level of use. In 2001, the Legislature and the CPUC essentially capped the lowest tiers from increases -- tiers 1 and 2 -- and those lower tier rates remained largely unchanged during 2001-2009. That means rate increases during that period fell almost exclusively into the higher tiers. This amplified the impact of rate increases on people who use more electricity in every part of our service area and, in turn, increased the cost of their electricity bills.

We are committed to helping limit or reduce costs to our customers, and it is our hope that through the recommendations in this report, PG&E can help customers during these tough times. PG&E's request to restructure rate tiers will bring our residential rates more closely into alignment with other utilities in the state. Our proposal to reset the residential rate tiers distributes electricity costs more equitably among all our customers. PG&E hopes this eliminates some of the "sticker shock" that can occur when a customer's usage crosses into the top rate tier, especially during peak summer and winter months.

In order to manage utility costs and rate increases, PG&E recommends modifications to certain aspects of CPUC energy procurement requirements, market structure, and statewide mandates. However, certain components of gas and electric rates are largely beyond the direct control of utilities, and instead result from market factors or policy mandates. Among these are the market price of natural gas used to supply retail customers and power generators; expenditures on public purpose programs mandated by law; the rate of uncollectible costs attributable to economic conditions faced by customers; the overall need for statewide infrastructure investment; the costs of Renewable Portfolio Standard (RPS) compliance; and the costs for compliance with greenhouse gas (GHG) emissions regulations and goals.

In addition, within the framework for the allocation of costs and rate design mandated by the Legislature and the CPUC, PG&E seeks to equitably allocate costs among its customers based on energy usage and category of customer. Crafting equitable allocation rules for revenue requirements across customer classes also poses challenges, largely due to rate designs mandated by law and the need to collect revenues to fund programs to benefit a specific set of customers, but are paid for by non-participating customers.

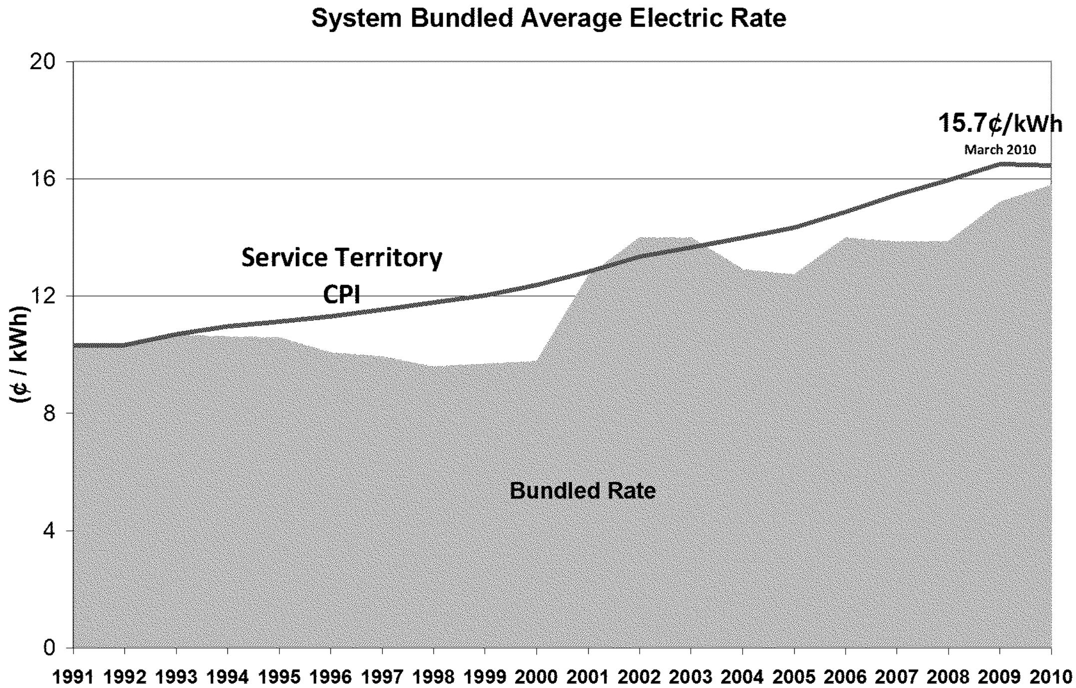
PG&E believes that the measures and actions in this report can have a beneficial near-term impact to its total cost of delivering safe, reliable, and cost-effective gas and electric services to its customers in California.

II. Overall Rate Approach

PG&E strives to provide its customers with reasonable rates for gas and electric service. PG&E understands that its customers value transparency and stability. Therefore, PG&E seeks to minimize the impact of rate adjustments made throughout the year. Generally, PG&E requests electric rate changes two times per calendar year (January and March). For gas rate changes, PG&E files monthly advice letter filings to change the gas commodity rate and seeks an annual gas transportation and public purpose program rate change. In addition, PG&E submits various filings to the CPUC throughout the year in response to specific Commission directive or changes to the utility business, to ensure that PG&E provides reliable and cost effective service to its customers.

PG&E also undertakes efforts to manage the timing of revenue changes and subsequent rate changes. Over the past twenty years, PG&E has been successful at managing electric customer rate increases. As illustrated in Figure 1, PG&E's system bundled average electric rate over the last twenty years has increased at lower rate than the service territory's consumer price index growth (CPI) (See Figure 1). This modest rate growth over time has resulted from careful utility cost containment and a general increase in sales (which moderate the upward pressure of revenue requirement growth). From time to time, PG&E also manages revenue collection through balancing accounts - tempering rate swings driven by differences in sales used to set rates and actual demands experienced. For example, in 2009, PG&E minimized swings in customer rates and bills via adjusting the timing of certain California Department of Water Resources-related payments and implementing a one-time Energy Resource Recovery Account bill credit to electric customers from balancing account overcollections. Similarly, to decrease pressure on customer bills during 2010, PG&E has requested approval to accelerate credits of balancing account over-collections, and defer collection of certain approved revenue requirements.

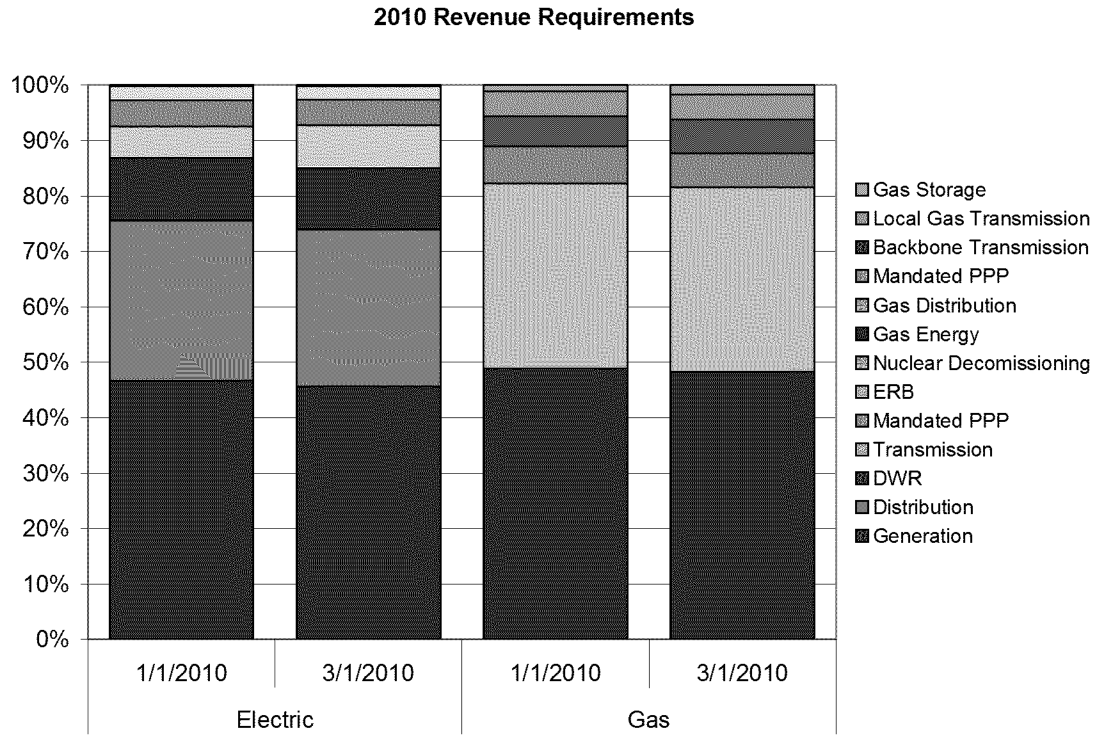
Figure 1. Historic Service Territory CPI vs. System Bundled Average Electric Rate. CPI provided by Economy.com



III. <u>Description of Revenue Requirement Components (Gas and Electric)</u>

This section summarized the major components of PG&E's gas and electric revenue requirements (RRQ) and how changes in those components are forecast to affect overall rates. The RRQs are classified into the following categories: (1) Energy/Generation, (2) Transmission/Backbone Transmission, (3) Distribution, (4) Public Purpose Programs/Mandated Programs (PPP), and (5) other. For example, Energy/Generation includes purchased power costs, utility-owned generation, Department of Water Resources charges (DWR), and pension revenue requirements linked to generation, among other items. Relative ranges for each RRQ category as a percent of total authorized 2009 RRQ, and analogous forecast trends for 2010, are provided for each RRQ section. Percentage ranges are calculated by comparing the category's revenue requirement to the total authorized revenue requirement during the course of the year (e.g. Authorized 2009 Electric Transmission RRQ divided by Total Authorized 2009 Electric RRQ). This calculation provides a means to discuss the relative magnitude of the major revenue requirement categories and the trend over time. Note that the focus is not on specific filings brought forth to the CPUC, but rather categories of revenue requirements that could have a potential impact on future rates.

Figure 2. High Level Breakdown of PG&E Revenue Requirements in 2010



Natural Gas

Natural gas revenue requirements are commonly grouped into the following six major categories: (1) Energy, (2) Distribution, (3) Public Purpose Programs/Mandated Programs, (4) Backbone Transmission, (5) Local Transmission, and (6) Gas Storage. For reference, an excerpt from the Advice 3060-G-A Annual Gas True-Up filing on December 22, 2009 is provided as Table 1 in the Appendix. The following statements reflect PG&E's expectations as of February 1, 2010, and may change throughout the course of the coming year due to various internal and external factors.

1) Energy-related gas revenue requirements represent approximately 44 percent to 55 percent of the total forecast gas revenue requirement in the upcoming 12 months. The revenue requirements are expected to trend upward, consistent with the market price of natural gas. For 2009, the energy revenue requirement represented about 46 percent of the total authorized gas revenue requirements.

2) Distribution-related gas revenue requirements constitute about 30 percent to 38 percent of the total forecast gas revenue requirements in the upcoming 12 months, and are expected to trend upward primarily due to additional maintenance and replacement work and system reliability-driven projects. For 2009, the distribution revenue requirement constituted about 36 percent of the total authorized gas revenue requirements.

3) Public Purpose Programs or Mandated-related gas revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Self-Generation

Incentive Program, and Energy Efficiency, represent approximately 6 percent to 7 percent of the total forecast gas revenue requirements in 2010. The revenue requirements are expected to trend slightly upward in the upcoming 12 months, mainly due to increased total discounts provided to customers on CARE. The increase in forecast CARE discounts is driven by the cost of gas and CARE participation. For 2009, mandated programs contributed about 7 percent of the total authorized gas revenue requirements.

4) Forecasted backbone transmission-related gas revenue requirements comprise approximately 5 percent to 7 percent of the total forecast revenue requirement in the coming year, and are generally expected to trend slightly upward in 2010. Increases in 2011 and 2012 are driven by replacement of aging facilities and retrofits/replacements for environmental regulations. For 2009, backbone transmission revenue requirements constituted about 7 percent of the total authorized gas revenue requirements.

5) Local transmission-related gas revenue requirements generally contribute 4 percent to 5 percent of PG&E's total forecast gas revenue requirement in the upcoming 12 months primarily due to capital additions for reinforcement projects, as well as operating and maintenance costs, particularly for integrity management. For 2009, local transmission represented approximately 5 percent of the total authorized gas revenue requirements.

6) Forecasted gas storage-related revenue requirements comprise approximately 1 percent to 2 percent of the total forecast revenue requirement in the coming year and are generally expected to trend upward. The revenue requirements are driven by new infrastructure and upgrades to existing facilities to ensure reliable, safe services, and access to diverse gas supplies. For 2009, gas storage revenue requirements contributed about 2 percent of the total gas revenue requirements.

Electric

Electric revenue requirements are commonly grouped into the following seven major categories: (1) Energy/Generation, (2) Distribution, (3) Department of Water Resources (DWR), (4) Transmission, (5) Public Purpose Programs, (6) Nuclear Decommissioning, and (7) Energy Revenue Bonds (ERB). For reference, excerpts from the December 31, 2009 Annual Electric True-Up filing are provided as Table 2 in the Appendix. The following statements reflect PG&E's expectations as of February 1, 2010, and may change throughout the course of the coming year.

1) Energy/Generation-related electric revenue requirements constitute approximately 45 percent to 50 percent of the total forecast revenue requirement in the coming 12 months. Of that, energy procurement costs represent roughly 67 percent of PG&E's generation revenue requirement in 2010. In contrast, utility-owned generation represents 22 percent of the generation revenue requirement. CTC (Competition Transition Charge) represents 2 percent to 3 percent of the total forecast revenue requirement in 2010 and remains relatively flat through the year. During 2009, generation revenue requirements comprised 50 percent to 51 percent of our total

authorized revenue requirement, and 68 percent of that was attributable to energy procurement. The CTC revenue requirement was 5 percent during 2009, due largely to undercollections resulting from differences in actual sales versus forecast sales. The year-over-year change in total generation-related revenue requirements reflects new utility-owned generation (e.g. Colusa) becoming operational during the 2010, projected reductions in purchased power, as well as attrition adjustments for inflation.

2) <u>Distribution-related electric revenue requirements</u>, including the California Solar Initiative and the SmartMeter™ program, comprise approximately 28 percent to 32 percent of the total and trend upward in the coming year. For 2009, Distribution revenue requirements represented 27 percent to 29 percent of the total authorized revenue requirement. The increase year-over-year is primarily due to balancing account adjustments made to compensate for differences in sales used to set rates and the actual sales levels experienced, which were lower than forecast.

3) <u>The DWR-related electric revenue requirements</u> (including DWR bond) comprise 4 percent to 11 percent of PG&E's forecast 2010 revenue requirement and are expected to decline on January 1, 2011, due to the expiration of DWR contracts and timing of indifference (transfer) payments between California's investor-owned utilities. During 2009, DWR-associated revenue requirements ranged from 9 percent to 13 percent of the total authorized revenue requirement. It should be noted that for ratemaking purposes, DWR is treated as a Generation cost.

4) <u>Transmission-related electric revenue requirements</u> contribute 6 percent to 8 percent of the total forecast revenue requirement in the coming year. Through 2009, transmission revenue requirements accounted for approximately 5 percent to 6 percent of the authorized total. Investments undertaken by other California Utilities and PG&E both contribute to the transmission revenue requirement growth over 2009. Transmission revenue requirements are generally expected to increase over time due to electric transmission investments undertaken by PG&E and the other California utilities to comply with North American Electric Reliability Corporation (NERC) reliability requirements, upgrades to existing assets, expansion of new service, and providing access to RPS-eligible power.

5) <u>Public Purpose Program-related electric revenue requirements</u> comprise 4 percent to 6 percent of PG&E's total forecast revenue requirement during 2010. In comparison, PPP represented less than 2 percent of the total authorized revenue requirement during 2009. Growth in PPP revenue requirements from 2009 to 2010 is tied to inflation of base costs as well as the expansion of key policy programs such as CARE and Energy Efficiency 2010 -2012 Programs which incorporate key elements of the Commission's Energy Efficiency Long Term Strategic Plan. In particular, the CARE shortfall projected for 2010 reflects the unexpected increase in actual customer discounts provided versus assumptions made when setting the CARE surcharge. And, the nearly $268 million energy efficiency refund provided in 2009 which does not carry through to 2010 also causes a major shift in revenue requirements year over year.

6) Nuclear Decommissioning-related electric revenue requirements represented less than 1 percent of PG&E's total authorized revenue requirement during 2009. That level is forecast to remain constant in 2010.

7) Energy Recovery Bond-related electric revenue requirements represent roughly 5 percent of PG&E's forecast revenue requirement in 2010 and will come to the end of their life during 2011. During 2009, ERB comprised between 1 percent and 2 percent of the total revenue requirement.

IV. Description of Rate Components (Gas and Electric)

Revenue requirements (RRQs) discussed in the previous section directly align with rate components. At the highest level, gas and electric rates can be described as revenue requirements divided by sales. Therefore, both revenue requirement changes and demand variations impact the actual rates for gas and electric service. RRQs expected to increase in the coming twelve months will tend to drive rates up. For those RRQs which trend down, rates similarly will be reduced. The rate pressures created by RRQs are modulated by differences in actual sales versus prior estimates (used to set rates). Adjustments in the allocation of revenue requirement across customer classes and rate tiers also impact the rates experienced by individual customers.

Published Load/Demand Forecasts

Customer sales volatility over time directly impacts the rates experienced by gas and electric customers. PG&E reviews load forecasts for its service territory on a regular basis to inform rate change filings taken to the Commission. Historically, aggregate customer sales increased at a pace which largely offset annual increases to revenue requirements. However, in recent years (2008 and 2009) as a result of the economic recession, the softening of sales growth means each customer has shouldered a larger portion of revenue requirement increases. The following section discusses the forecast trends for Gas and Electric loads during 2010.

Gas

As described in the Electric subsection below, PG&E's service area economy is expected to remain weak through 2010. This will impact both electricity demand and gas throughput. PG&E's forecast projects 2010 gas sales for all three major gas customer classes - residential, commercial, and industrial - to show modest declines in usage this year. Looking further out, residential and commercial demand are expected to change very little from 2010 to 2015.

The residential gas demand forecast incorporates real residential rates, number of households in PG&E service territory, heating degree days and the percentage of households built after 1978, or when title 24 multifamily energy efficiency standards went into effect. Unlike electricity, which has innumerable residential uses, the main residential use for gas is space and water heating, therefore requiring customer growth to drive usage growth. With little customer growth and unemployment remaining high, residential demand is projected to be essentially flat over 2009 totals (-0.1 percent). Since space heating is the principle use of gas in the commercial sector (as it is for residential use), growth is dependent on the level of business activity within the sector. With commercial vacancy rates already high, and with the potential for them to climb even higher in 2010, gas usage in this sector is projected to decline by nearly 2 percent this year. The soft economy will also drive industrial sales lower in 2010 by 1.4 percent.

Conversely, demand for gas used in Electric Generation is expected to be higher by 10 percent in 2010 than 2009. Many factors drive the volatility in gas demanded for electric generation, including the economy, gas prices, hydroelectric generation capacity, new generation facilities coming online, nuclear generating capacity, and others.

Electric

For 2010, economic growth within PG&E's service territory, as forecast by Economy.com, is projected to remain soft. The economy will continue to lose jobs, and household income will continue to decline. With this outlook as a backdrop, PG&E's forecast projects electric sales for 2010 declining at 0.6 percent relative to 2009 observed sales. If the economic rebound gains traction in 2011, PG&E expects to see electric sales growth turn positive, increasing by 1.1 percent. The attached table shows historic sales trends in greater detail (Appendix B). Consistent with the notion that 2010 represents a "rocky bottom" to this recession, PG&E's sales projections for 2010 are mixed.

Electric customer (billings) growth has also been dramatically impacted by the recession. For 2010, customer growth will exhibit the same sluggishness as the economy at large. PG&E's forecast shows an addition of about 25,000 customers in 2010, which pales next to the 70,000-80,000 PG&E regularly observed annually during the middle of the last decade. By 2011, a recovering economy should yield stronger customer growth.

Among the four major electric customer classes (residential, agricultural, industrial, commercial) two are projected to show declining sales, one is projected to be flat, and one is projected to show an increase compared to 2009. With household incomes still declining and job security tenuous, residential usage is projected to decline by 1.3 percent in 2010. Agricultural sales (primarily groundwater pumping) have grown substantially during the last 3 years in response to below normal rainfall levels. With assumed normal rainfall built into the forecast, however, agricultural demand is projected to decline in 2010 (-5.5 percent), but remain at a high level of usage by historical standards. Industrial sales, after declining a dramatic 9 percent in 2009, will essentially remain flat in 2010 (-0.2 percent). The commercial sector is the one sector projected to show any growth at all, and even this will be meager at just 0.6 percent. Increased consumer spending and higher service sector output are the main drivers here, but both are on shaky footing and any erosion of this sector's growth could turn commercial sales negative as well.

V. Management of Key Rate Components

PG&E is committed to controlling costs while providing safe and reliable gas and electric service to its customers. However, there are many key drivers that affect customer rates which fall outside of PG&E's control. Among these are the market price of natural gas, actual retail sales volumes, uncollectable accounts, weather, interest rates, and permitting process delays. Despite these factors, PG&E diligently seeks to manage its costs across all categories to make efficient and effective use of revenues collected from customers.

VI. 2010 CPUC Filing Outlook

Attached for your reference is Appendix A, which reflects key filings data provided previously to the Energy Division (December 2009). The table has been modified per the currently anticipated filing schedule for 2010, and now also reflects the revenue requirement or rate components (see Section III) that are primarily affected by each filing. This is not an exhaustive list of PG&E's 2010 filings; rather it incorporates planned regulatory filings which are known at this time to have a rate impact for gas or electric customers. Actual filing dates, amounts of requests, and actual revenue requirements authorized or settled are subject to change via the normal regulatory approval processes of the CPUC and other regulatory agencies.

VII. Recommendations to the CPUC and Legislature

In this section, PG&E provides its recommendations for measures that can be undertaken in the next 12 months to limit utility cost and rate increases, in addition to the recommendations in the Introduction. These recommendations address factors related to the economy, state and federal energy policy, and regulatory policies and orders, which PG&E believes significantly impact utility costs and resulting customer rates in the near to medium-term.

PG&E is committed to meeting California's energy and environmental goals for reducing greenhouse gases (GHG); enhancing its infrastructure and improving its operations. However, PG&E believes environmental goals should not be met *at any cost* – care should be taken to address rate impacts of choices as GHG emissions goals are defined. In the coming year, PG&E recommends that several key State policies and procedures could be modified or clarified to support more effective, efficient and beneficial deployment of revenues collected from PG&E customers. PG&E believes that adoption of these recommendations at the State level will help to alleviate significant upwards cost pressures and ultimately reduce customer rates for gas and electric service.

1. Gas procurement policies

PG&E procures natural gas for direct consumption by a large portion of residential and small business customers (commonly referred to as core procurement gas customers) and to supply PG&E-owned as well as third-party owned electric generation facilities which supply electricity to PG&E's bundled electric customers. To minimize costs of natural gas procurement and to meet reliability targets, PG&E purchases from various supply sources and also negotiates long-term contracts on a variety of transportation and storage systems. PG&E also employs financial hedging instruments to maintain cost stability and to limit the impact of spikes in natural gas prices on customer bills.

PG&E supports the implementation of initiatives that provide PG&E and its customers with expanded access to diverse supply regions for natural gas, such as the long-term transportation contracts on the proposed Ruby Pipeline. These transportation contracts, which were approved by the CPUC in 2008 and executed by the company in 2009, will provide PG&E customers with direct access to natural gas from the Rockies region beginning in 2011. PG&E also supports continued State energy policies and initiatives to expand and evaluate new options for natural gas supply, transportation and storage in order to effectively manage the costs of procuring natural gas for our customers.

2. Retail Electricity Dynamic Pricing

The CPUC has initiated an ambitious policy toward implementation of dynamic retail electricity pricing in PG&E's service territory. Dynamic pricing is defined as pricing that reflects real time system costs and therefore requires the functionality of the newly installed SmartMeter™ infrastructure (which provides hourly usage data). Dynamic pricing is expected to have a number of benefits including: lowering costs by more closely aligning retail rates and wholesale system conditions, thereby promoting economically efficient decision making; improving system reliability by providing an incentive to lower usage when the supply and demand balance is strained or in times of system emergencies; reducing greenhouse gas emissions by reducing the need to operate inefficient resources; and finally, providing a key building block of the smarter energy grid.

In 2010, PG&E will begin to default its largest customers to a form of dynamic pricing called Peak Day Pricing, which provides specific rates for peak energy days, and lower rates during other days, year-round. Though customers will be able to opt out, with the availability of first year bill protection, participation is expected to be much higher than it would be otherwise. In 2011, this initiative extends to all non-residential commercial mass market customers (about 500,000 customers), who will lose the option to take service on rates that are not time-differentiated.

Also, in 2011, PG&E expects to begin to offer Peak Day Pricing to residential customers (about 4.5 million customers) on an optional basis, and to implement Peak Time Rebate rates for residential customers as part of the default rate offerings. Peak Time Rebate rates provide lower credits for reducing usage during peak days on a default basis, with a higher credit for customers with enabling technology. As a result, bundled residential customers will have a number of possible rate options: standard and time of use rates with Peak Time Rebate (with or without enabling technology) and Peak Day Pricing.

Finally, closely following the implementation of Peak Day Pricing, all customers will be offered the option of Real Time Pricing, which charges customers for energy indexed to the California Independent System Operator's day-ahead market prices.

Implementing dynamic pricing on a default basis for customers is an ambitious effort requiring significant and costly systems changes and extensive customer education to achieve the demand response benefits associated with these offerings. With proper time and investment, PG&E is confident that it can implement these initiatives with the Commissions objectives in mind. However, over next 12 months, the CPUC, other energy policymakers, customers and PG&E need to proactively work together to ensure that the economic impacts and costs of dynamic pricing are managed and contained so that the full benefits of dynamic pricing can be realized without excessive cost or unanticipated impacts on customers.

In addition, changes in law enacted in SB 695 would afford the opportunity to default all residential customers to "Peak Day Pricing," (a form of dynamic pricing) as early as 2013. PG&E recommends that any such effort be undertaken carefully and only after customers, utilities and regulators can evaluate to the rate impacts of defaulting residential customers onto these new rates. PG&E, customers and the Commission can learn from the efforts to default commercial mass market customers in 2011. Further, PG&E recommends that the default options should be studied carefully to ensure the best approaches and options are determined before any such program is implemented.

3. Other Electric Rate Design Policies

PG&E and the Commission have endorsed rate policies based on cost of service. PG&E believes that such policies are appropriate and should continue. Such policies are sustainable because they encourage efficient decision making by customers. At times, departing from cost-based rates can be appropriate if justified in order to accomplish other public policy objectives. Such objectives include energy efficiency, benefits provided to low income customers, mitigation of rate changes from year to year, promotion of renewable generation, GHG emissions reductions, and encouraging innovation and developing technologies. However, each departure from cost-based rates carries with it the risk that one set of customers—the non-benefiting customers—will be paying higher than cost-based rates to subsidize another set of customers—the benefiting customers. Thus, each departure from cost-based rates needs to be carefully evaluated to determine whether the rate increases to non-benefiting customers are reasonable in light of the overall benefits to benefiting customers and society at large. While beneficial from a policy perspective, programs that support these ends (such as net metering and standby waivers) can result in costs being shifted to other customers. Whenever a customer reduces their own contribution to cost of service to below avoided costs, the difference is paid by other customers. Because our current rate structure recovers fixed costs in a variable rate, any program that reduces participants' costs can create upward pressure on rates for other customers.

In the next 12 months, PG&E recommends that the Commission carefully evaluate and re-examine several examples of non-cost-based ratemaking that are significantly impacting the level of current rates and costs to customers.

The first and most immediate area of concern that should be evaluated over the next 12 months is residential electric rate design, where a 5 "tier" rate structure is employed. This structure, first put in place during the energy crisis ten years ago, has grown to have a punitive effect on customers, and does not reflect the true cost of service. The effects of this structure were most recently seen in customers' adverse reaction to bills in the Central Valley during the summer of 2009. One significant driver of these complaints was the rate change from summer of 2008 to summer of 2009, when the Tier 5 rate increased from 36 to 44 cents per kWh. At this rate level, customer bill volatility from month to month, particularly in hotter areas of the service territory, can be extreme in nature. Without modification, rates projected for the summer of 2010 are expected to be even higher. PG&E has asked for expedited treatment of several initiatives designed to lower upper tier rates for summer of 2010, and respectfully requests the Commission's support to make these changes in time for summer 2010. While legislation was recently passed to help address this problem by allowing limited increases to Tier 1 and Tier 2 rates, the Commission and Legislature should be mindful that this approach alone will not prevent upper Tier rates from continuing to be punitive in the longer term. PG&E recommends the spread in tiered rates be monitored over time and legislative change be sought to more fully address this issue.

The second area of concern that should be evaluated is the non-cost-based subsidies by retail customers to owners or operators of distributed electricity generation systems.

California has had a long history of implementing policies that encourage market acceptance of distributed electric generation systems. Promotional policies have included waiving charges designed to recover the fixed costs of utility assets required to deliver service to these customers, as well as above-market prices paid for excess energy generated by those distributed resources. As a result, rates for other non-participating customers have increased to cover that shortfall or overpayment, resulting in rates which do not reflect true cost-of-service. Increased penetration of distributed generation beyond today's relatively modest levels will call for a deliberate consideration of rate design changes to moderate rate increases to non-participating customers. Therefore, PG&E recommends policymakers explore and adopt alternative ways to provide transparency and fairly allocate the transmission, distribution and above-market energy costs associated with distributed generation across all system customers.

The California Legislature has required policies such as retail net metering; above market payments for generation exports to the grid; incentive programs; and exemptions from standby related charges. These policies, which provide a subsidy to participating customers, are viewed by state policy-makers as an important way to temporarily encourage market deployment of these technologies. Over the next 12 months, PG&E recommends that the California Legislature and other energy policymakers carefully evaluate the level of these subsidies and whether these subsidies should continue to be paid by non-participating utility customers through their rates. . As such, subsidies are not an entitlement and should not be perceived as extending indefinitely.

PG&E recommends that provision of distributed generation subsidies be monitored closely in order to ensure that the subsidies are no greater than necessary in light of the public and societal interest, particularly where the subsidies may be continuing beyond the development stage of the subsidized distribution generation entity or technology. Such subsidies should be eliminated when the various industries mature. Subsidies that do not reflect true economics may not promote efficient deployment of resources. Furthermore, over time, it is important that distributed generation systems be separately metered and managed in order to provide complete transparency around the subsidies provided and the generation characteristics of these units relative to the load, in order to more effectively integrate these units into the utility grid. As the Legislature and CPUC continue to develop or extend subsidies, they should be mindful of the need to balance distributed generation policies against the negative impacts on rates for non-participants. The CPUC and Legislature should recognize that ultimately these cost shifts may not be sustainable, reasonable or fair.

4. Increasing Renewable and Alternative Energy and Reducing Greenhouse Gas Emissions at Reasonable Cost

Assembly Bill (AB) 32 requires the gradual reduction of greenhouse gas (GHG) emissions in California to 1990 levels by 2020 on a schedule beginning in 2012. In December 2008, the California Air Resources Board (CARB) adopted a scoping plan that contains recommendations for achieving the 2020 target which include developing a multi-sector cap-and-trade program, achieving a 33 percent renewable portfolio standard (RPS) by 2020, increasing energy efficiency, and expanding the use of combined heat and power facilities. In addition, the California Legislature, Governor and CPUC are all considering separate legislation, policies and programs that would increase renewable electricity to 33% as part of the renewable portfolio standard as well as increase the availability of "combined heat and power" generating facilities.

As state policymakers move forward with implementation of these environmental and energy goals, PG&E continues to stress the importance of managing costs to California consumers and businesses by pursuing cost-effective reduction strategies and cost containment provisions. The ultimate success of such efforts will depend largely on key design issues for the cap-and-trade program, -- such as the number of emission allowances allocated to the Utility for benefit of our customers, the development of robust cost containment tools for the price of emission allowances, use of emission offsets, and the ability to link to other cap-and-trade programs -- in addition to renewable and energy efficiency issues as described below.

Achieving a 33 percent renewable portfolio standard is the highest priced GHG-reducing option included in ARB's Scoping Plan, at $133/ton. Any GHG or renewables targets contemplated by state policymakers must therefore include measures to manage consumer costs and ensure that the costs of reaching these goals are reasonable to consumer, particularly retail electricity customers served by utilities such as PG&E that must meet the goals. One way to protect consumers and to help limit or contain the costs of meeting both these goals is to expand the eligibility of renewable resources that also reduce greenhouse gas emissions. Quite simply, as more greenhouse gas emissions-free renewable resources are available, no matter where located, the cost of achieving both goals will go down. A regional approach is essential to ensure sufficient renewable resources are available. Authorization to purchase unbundled Renewable Energy Credits would also increase the supply. Another important component is a price protection mechanism that would mitigate against substantial price increases if at any time the goals become to costly to meet or result in unanticipated unreasonably rates or costs to utility customers. While not perfect, the current RPS legislation contains a cost containment mechanism and such a backstop should be included in any new program. It is also important that all public utilities, including investor-owned and publicly owned, are bound by the same rules and able to avail themselves of the same types of resources.

Likewise, PG&E supports efficient Combined Heat and Power (CHP) that ensures statewide GHG emission reductions, provided that CHP is priced at market and it does not adversely impact grid reliability. CHP incentives should be balanced – encouraging efficiency CHP development, but not significantly shifting costs to bundled customers. The AB 32 Scoping Plan included a CHP Program Measure which is estimated to yield an annual GHG reduction of 6.7 MMT by 2020 from the deployment of new, highly efficient CHP. Pursuant to AB32, the California Air Resources Board must promulgate regulations by January 1, 2011 addressing if and how this CHP-specific reduction target is to be realized.

PG&E recommends that state policymakers enact policies that will achieve meaningful GHG emission reductions by maintaining, repowering and/or adding new, efficient CHP resources while minimizing customer costs; and that will maintain system reliability by limiting required unneeded amounts of must-take resources that could displace non-GHG emitting resources. PG&E further recommends that policymakers coordinate consistent regulatory treatment across state agencies so that utilities do not incur costs to purchase CHP power without also receiving the GHG reduction credit associated with its purchase, and that utilities pay for competitively priced (not "above-market") electricity from existing CHPs under new contracts.

If undertaken over the next 12 months, each of these initiatives will help limit and contain rate increases and costs to utility customers while also achieving the State's priority environmental and energy policy goals in a balanced, cost-effective manner.

5. Once-Through Cooling Policy for Existing Powerplants

Since 2006, the State Water Resources Control Board (SWRCB) has issued four preliminary proposals outlining the reduction of once-through cooling (OTC) technology in generation facilities. There are currently 18 California power plants that use OTC, including PG&E's Diablo Canyon facility (Humboldt goes off-line in 2010 when the new facility begins operations). The SWRCB is now considering the adoption of a policy to phase out the use of once-through cooling at electric generation facilities. In particular, the SWRCB has proposed that these plants can either be retrofit or re-powered with another cooling technology or shut down completely. Compliance deadlines under the proposal range from 2011 to 2024 with compliance deadlines staggered in a manner to help assure system reliability.

The California utilities have procurement contracts with a number of entities that employ once-through cooling, and also operate two nuclear power plants which rely on once-through cooling. A change in the state's policy to disallow the use of once-through cooling could result in billions of dollars in power plant retrofitting costs to utility customers. PG&E has submitted an engineering study to the SWRCB that indicates retrofitting costs for Diablo Canyon alone could amount to $4.5 billion. PG&E continues to advocate for an orderly transition away from OTC through planned repowering, replacement or retirement at the state's fossil plants, and for cost-benefit analysis at the nuclear facilities to determine whether retrofit is appropriate given the substantial costs and collateral environmental impact of moving to closed-cycle cooling in terms of GHG emissions and other air quality impacts.

6. Streamlining and Expediting Permitting and Approvals of New Transmission and Distribution Facilities

Studies prepared by the CPUC, California's Renewable Energy Transmission Initiative (RETI) and the California Independent System Operator (CAISO) have all identified the need for substantial investment in electric transmission to achieve the state's RPS and GHG emission reduction targets. Planning, siting and constructing electric transmission infrastructure requires navigating a complex and costly maze of regulations and requirements. In order to limit the costs of delay and "red tape" being imposed on utility customers for these essential project, the Energy Commission, CPUC, California Legislature and involved state agencies should immediately speed these processes and reduce the overall cost of developing the infrastructure necessary to achieve California's energy policy goals.

While not as high profile as the electric transmission expansion studies, upgrades will be needed to the electric distribution system to support higher penetration of distributed generation and electric vehicles. The underlying generation projects and the distribution system upgrades will also require permitting by various federal, state and local agencies. Existing planning and siting approval processes require between seven and ten years to complete an electric transmission project. Achieving the targeted RPS and GHG policy goals will be impossible if the current processes are not improved. California policymakers and various permitting agencies should also immediately speed the processes of developing these projects.

Tables and Appendices

Table 1. Excerpt from Advice 3060-G-A Annual Gas True-Up filing for Rates Effective January 1, 2010.

Pacific Gas and Electric Company
San Francisco, California
U 39

Cancelling Revised *Cal. P.U.C. Sheet No.* 27953-G
Revised *Cal. P.U.C. Sheet No.* 27393-G

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 2

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

Description	Amount ($000) Core	Noncore	Unbundled	Core Procurement	Total
GRC BASE REVENUES (Incl. F&U) (1):					
Authorized GRC Distribution Base Revenue					1,139,444 (I)
Less: Other Operating Revenue					(26,023)
Authorized GRC Distribution Revenues in Rates	1,076,931 (I)	36,490 (I)			1,113,421 (I)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:					
G-10 Procurement-Related Employee Discount	(2,624)(R)				(2,624)(R)
G-10 Procurement Discount Allocation	1,103 (R)	1,521 (R)			2,624 (R)
Less: Front Counter Closures	(355)				(355)
Core Brokerage Fee Credit	(9,581)				(9,581)
GRC Distribution Base Revenue with Adj. and Credits	1,065,474 (I)	38,011 (I)			1,103,485 (I)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (2):					
Transportation Balancing Accounts	137,518 (I)	11,908 (I)			149,426 (I)
Self-Generation Incentive Program Revenue Requirement	2,586	3,534			6,120
CPUC Fee	2,076	2,718			4,794
ClimateSmart	0 (R)	0 (R)			0 (R)
SmartMeter™ Project	45,997 (I)				45,997 (I)
Winter Gas Savings Plan (WGSP) – Transportation	2,274 (I)				2,274 (I)
Franchise Fees and Uncollectible Expense (F&U) (on items above)	2,179 (I)	239 (I)			2,418 (I)
CARE Discount included in PPP Funding Requirement	(109,433)(R)				(109,433)(R)
CARE Discount not included in PPP Surcharge Rates	0				0
Transportation Forecast Period Costs & Balancing Account Balances	83,197 (I)	18,399 (I)			101,596 (I)
GAS ACCORD REVENUE REQUIREMENT (Incl. F&U) (3):					
Local Transmission	114,854 (I)	49,146 (I)			164,000 (I)
Customer Access Charge – Transmission		5,174			5,174
Storage	42,093		7,499		49,592
Carrying Cost on Noncycled Storage Gas	1,757		251		2,008
Backbone Transmission/L-401	80,394 (R)		160,593 (R)		240,987 (R)
Gas Accord Revenue Requirement	239,098 (I)	54,320 (I)	168,343 (R)		461,761 (I)

(1) The authorized GRC amount includes the distribution base revenue and F&U approved effective January 1, 2007, in General Rate Case D.07-03-044, and $22M for Attrition as approved in AL 2877-G, 2954-G, and AL 3050-G. The GRC distribution base revenue is allocated to core and noncore customers in Cost Allocation Proceedings, as shown in Part C.3.a. (T)

(2) The total 2009 SGIP revenue requirement (RRQ) was approved in D.09-12-047. Per D.06-05-019, SGIP costs were removed from wholesale gas rates on July 1, 2006. The Climate Protection Tariff RRQ for 2009 was approved in D.06-12-032. On April 27, 2009, PG&E filed an Application requesting a 2-year extension of the ClimateSmart program. PG&E seeks no additional customer funding. The SmartMeter™ Project RRQ was approved in D.06-07-027 and AL 2752-G/G-A. The Energy Division approved PG&E's AL 3039-G for the WGSP costs, which are recovered in commercial customers" rates beginning January 1, 2010. (T)

(3) The Gas Accord IV RRQ effective January 1, 2009, was adopted in D.07-09-045. Storage revenues allocated to load balancing are included in unbundled transmission rates.

(Continued)

Advice Letter No:	3060-G-A	*Issued by*	*Date Filed*	December 22, 2009
Decision No.	05-06-029	***Brian K. Cherry***	*Effective*	January 1, 2010
		Vice President	*Resolution No.*	
2C12		*Regulatory Relations*		

Table 1(continued). Excerpt from Advice 3060-G-A Annual Gas True-Up filing for Rates Effective January 1, 2010.

Pacific Gas and Electric Company		Revised	Cal. P.U.C. Sheet No. 27954-G
San Francisco, California	Cancelling	Revised	Cal. P.U.C. Sheet No. 27781-G
U 39			

GAS PRELIMINARY STATEMENT PART C
GAS ACCOUNTING TERMS & DEFINITIONS

Sheet 3

C. GAS ACCOUNTING TERMS AND DEFINITIONS (Cont'd.)

2. ANNUAL GAS REVENUE REQUIREMENT AND PPP FUNDING REQUIREMENTS: (Cont'd.)

Description	Amount ($000) Core	Noncore	Unbundled	Core Procurement	Total	
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (4):						
Illustrative Gas Supply Portfolio				1,852,955 (R)	1,852,955 (R)	
Interstate and Canadian Capacity				216,719 (I)	216,719 (I)	
WGSP – Procurement – Residential				2,476 (R)	2,476 (R)	
F&U (on items above and Procurement Account Balances Below)				25,270 (R)	25,270 (R)	
Backbone Capacity (Incl. F&U)	(61,697) (I)			61,697 (I)	0	
Backbone Volumetric (Incl. F&U)	(18,698) (I)			18,698 (R)	0	
Storage (Incl. F&U)	(42,093)			42,093	0	
Carrying Cost on Noncycled Storage Gas (Incl. F&U)	(1,757)			1,757	0	
Core Brokerage Fee (Incl. F&U)				9,581	9,581	
Procurement Account Balances				11,692 (I)	11,692 (I)	
Illus. Core Procurement Revenue Requirement	(124,245) (I)			2,242,938 (R)	2,118,693 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	1,283,524 (I)	110,730 (I)	168,343 (R)	2,242,938 (R)	3,785,535 (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (5):						
Energy Efficiency (EE)	58,377 (R)	6,498 (R)			64,875 (R)	
Low Income Energy Efficiency (LIEE)	55,734 (I)	6,204 (I)			61,938 (I)	
Research, Demonstration and Development (RD&D)	6,725 (R)	3,861 (I)			10,586 (I)	
CARE Administrative Expense	1,113 (R)	730 (I)			1,843 (I)	
BOE and CPUC Administrative Cost	188 (I)	108 (I)			296 (I)	
PPP Balancing Accounts	1,858 (R)	(4,348) (R)			(2,490) (R)	
CARE Discount Recovered from non-CARE customers	66,085 (I)	43,348 (I)			109,433 (I)	
Total PPP Funding Requirement in Rates	190,080 (I)	56,401 (I)			246,481 (I)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	1,453,604 (I)	167,131 (I)	168,343 (R)	2,242,938 (R)	4,032,016 (R)	
Low Income Energy Efficiency Not In Rates	0 (R)	0 (R)			0 (R)	(D)
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	1,453,604 (I)	167,131 (I)	168,343 (R)	2,242,938 (R)	4,032,016 (R)	

(4) The credits shown in the Core column represent the core portion of the Gas Accord RRQ that is included in the Illustrative Core Procurement RRQ, and are shown here to avoid double counting these costs in the total. The Gas Supply Portfolio cost includes a forecast of carrying cost on cycled gas in storage, and an illustrative commodity and shrinkage cost based on the Weighted Average Cost of Gas (WACOG) of $0.59828 per therm. Actual gas commodity costs change monthly. WGSP costs, approved in AL 3039-G, will be recovered in residential rates effective April 1, 2010. (T) (T)

(5) The PPP funding requirement is recovered in gas PPP surcharge rates pursuant to D.04-08-010 and 2010 PPP surcharge AL 3057-G and includes LIEE program funding adopted in D.08-11-031, EE program funding adopted in D.08-10-027, CARE annual administrative expense adopted in D.08-11-031, and excludes F&U per D.04-08-010. (T) (D)

(Continued)

Advice Letter No:	3060-G-A	Issued by	Date Filed	December 22, 2009
Decision No.	05-06-029	**Brian K. Cherry**	Effective	January 1, 2010
		Vice President	Resolution No.	
3C15		Regulatory Relations		

Table 2. Excerpted from Advice 3518-E-A Annual Electric True-Up filing for Rates Effective January 1, 2010.

Table 2: Annual Electric True-Up Projected 2010 Revenue Requirements

Line #		Test Year 2010 RRQ A	12/31/09 Forecast Under/(Over) collected BA Amortization B	Total Projected 2010 Revenues C = A + B
1	**CPUC Jurisdictional**			
2	**Distribution**			
3	Distribution/DRAM [1]	3,058,541,472	140,907,862	3,199,449,334
4	Self Generation Incentive Program	30,186,419	0	30,186,419
5	Environmental Enhancement	10,102,550	0	10,102,550
6	CPUC Fee	20,644,796	0	20,644,796
7	Advanced Metering/SBA	107,497,541	32,573,331	140,070,872
8	Demand Response/DREBA/DRRBA	35,914,565	715,457	36,630,022
9	Air Conditioning Cycling/ACEBA/DRRBA	48,613,035	0	48,613,035
10	ClimateSmart	0	0	0
11	California Solar Initiative	106,076,775	0	106,076,775
12	HSM	0	8,966,589	8,966,589
13	ATFA	0	(254,962)	(254,962)
14	CEMA	0	5,922,000	5,922,000
15	PCBA	0	0	0
16	CEEIA	29,382,897	2,031,108	31,414,005
17	NTBA	0	0	0
18	LCPERMA	0	346,248	346,248
19	DPMA	0	0	0
20	**Generation**			
21	Utility Retained Generation Base/UGBA	1,340,530,602	324,313,742	1,664,844,344
22	Electric Procurement/ERRA	3,731,717,921	81,210,898	3,812,928,819
23	DWR--Power Charge/PCCBA	930,339,038	73,825,458	1,004,164,496
24	DWR Franchise Fees	10,822,923	0	10,822,923
25	BCRSBA	0	(976,899)	(976,899)
26	FERABA [2]	0	4,499,049	4,499,049
27	HA	0	0	0
28	LTAMA	0	290,941	290,941
29	MRTUMA	0	0	0
30	RPSCMA	0	0	0
31	CARB	0	0	0
32	**Ongoing CTC/MTCBA**	353,029,017	47,732,678	400,761,695
33	**Rate Reduction Bond Memorandum Account** [1]	0	0	0
34	**Energy Cost Recovery Bonds**			
35	(1) Dedicated Rate Component Series 1	303,859,661	0	303,859,661
36	(2) Dedicated Rate Component Series 2	152,788,191	0	152,788,191
37	(3) ERB Balancing Account (ERBBA)	(23,686,226)	(117,415,768)	(141,101,994)
38	**Nuclear Decommissioning**	25,697,000	336,624	26,033,624
39	**Public Purpose Programs**	0	0	0
40	(1) Energy Efficiency	120,670,462	0	120,670,462
41	(2) RDD	35,217,516	0	35,217,516
42	(3) Renewables	36,826,418	0	36,826,418
43	(4) LIEE	90,043,760	0	90,043,760
44	PPPRAM	0	(5,077,665)	(5,077,665)
45	CAREA	7,448,408	52,070,991	59,519,399
46	Procurement EE/PEERAM	250,724,532	4,076,633	254,801,165
47	**DWR Bonds**	411,132,926	0	411,132,926
48	**Total CPUC Jurisdictional**	**11,224,122,199**	**656,114,315**	**11,880,236,514**
49	***CPUC Revenues at Present Rates***			11,456,693,992
50	***Change in CPUC Jurisdictional***			423,542,522
51	***Total FERC Jurisdictional***			719,546,627
52	***FERC Revenues at Present Rates***			751,113,742
53	***Change in FERC Jurisdictional***			(31,567,115)
54	**Grand Total Projected Revenues**			**12,599,783,141**
55	**Total Revenues at Present Rates**			**12,207,807,734**
56	**Total Change**			**391,975,407**

Notes:
1. The 12/31/09 forecast Distribution/DRAM balance includes the 12/31/09 forecast Rate Reduction Bond Memorandum Account balance as authorized in AL 3502-E.
2. The 12/31/09 forecast FERABA balance of $4,499,049 includes a discount portion of $3,835,228, which gets allocated to generation rates; and administrative costs of $663,821 which gets allocated to distribution rates.

Appendix A. Key Filings Table

Requests Impacting Customer Rates

Filed During the Year of 2010

SB 695 Reporting Requirement

Filing Description	Anticipated Filing Date	Expected Implementation	Impacted Rate	Impacted Rate Component
Q1 2010				
March 1 Rate Change (To Implement TO12 Rates)	Jan	3/1/10	Electric	Transmission
Rate Design Window 2010 (Peak Time Rebate)	Jan	5/1/11	Electric	Energy/Generation
Diablo Seismic Survey (3D)	Jan	1/1/12	Electric	Energy/Generation
ERRA 2009 Compliance Filing - Includes MRTU Cost Recovery	Feb	-	Electric	Energy/Generation, Competition Transition Charge (CTC)
General Rate Case (GRC) 2011 Ph II - Dynamic Pricing	Mar	5/1/11	Electric	PPP, Distribution, Energy/Generation, Competition Transition Charge (CTC)
General Rate Case (GRC) 2011 Ph II - Gas	Mar	5/1/11	Gas	Energy, Distribution, Public Purpose Programs/Mandated Programs
Q2 2010				
Energy Resource Recovery Account (ERRA) 2011 Forecast	Jun	1/1/11	Electric	Energy/Generation, Competition Transition Charge (CTC)
Core Procurement Incentive Mechanism Sharehold Award	TBD	10/1/10	Gas	Energy (gas procurement)
Q3 2010				
FERC - TO13	Jul	3/1/11	Electric	Transmission
Winter Gas Savings Program (2010-2011)	Aug	9/13/10	Gas	Energy (gas procurement), Distribution
Annual Electric True-Up (AET) 2011	Sep	1/1/11	Electric	Transmission, PPP, Distribution, Energy/Generation, DWR, CTC, ERB
DWR 2011 Revenue Requirement Forecast Filing	TBD	TBD	Electric	DWR
Real Time Pricing - Residential Default	TBD	TBD	Electric	Energy/Generation
Q4 2010				
FERC TRBA/ECRA/RSBA Filing	Oct	1/1/11	Electric	Transmission
Public Purpose Program Surcharge Gas Rate Filing 2010 - Advice Letter	Oct	1/1/11	Gas	Public Purpose Programs/Mandated Programs
SB 695 Res Rate Change (T1 & T2) Advice Letter	Nov	1/1/11	Electric	Distribution, Energy/Generation
Energy Resource Recovery Account (ERRA) 2010 Forecast - Update	Nov	1/1/11	Electric	Energy/Generation, Competition Transition Charge (CTC)
Annual Gas True-Up (AGT) 2011	Nov	1/1/11	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage
Annual Gas True-Up (AGT) 2011 - Advice Letter Update	Dec	1/1/11	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage
Annual Electric True-Up (AET) 2011 - Advice Letter Update	Dec	1/1/11	Electric	Transmission, PPP, Distribution, Energy/Generation, DWR, CTC, ERB
FERC TACBA Filing	Dec	3/1/11	Electric	Transmission

Appendix B. Electric Load Forecast Detail

place holder for externally-approved sales forecast

Appendix C. Gas Load Forecast Detail

place holder for externally-approved sales forecast