Pacific Gas and Electric Company

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March 4, 2011

Ms. Gurbux Kahlon
Manager, Rate Regulation
Analysis and Policy Branch
Energy Division
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Re: SB 695 2011 Compliance Report - Pacific Gas & Electric Co.

Dear Ms. Kahlon:

Attached, please find PG&E's final version of the 2011 SB 695 Section 8 (PUC Section 748) compliance report. We hope you will find it useful in compiling the Energy Division's report to the Legislature.

Sincerely,

Amrit Singh

cc: (via e-mail)
Julie Fitch, Energy Division
Gurbux Kahlon, Energy Division
Niki Bawa, Energy Division

SB 695 Report To California Public Utility Commission Energy Division
Reporting Entity: Pacific Gas and Electric Company
Year: 2011

I. Summary of Report and Recommendations to CPUC and Legislature to Reduce Utility Costs and Rates

Pursuant to the requirements of Public Utilities Code section 748(b), Pacific Gas and Electric Company (PG&E) appreciates the opportunity to provide its annual 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 requirements, a discussion of PG& E's management of its costs and rates and a schedule of PG&E's filings that affect rates in 2011 and 2012 (Table 3 in the Appendix).

In these tough economic times, PG&E knows how important it is for our customers to keep monthly electricity and gas costs to a minimum. PG&E understands that electricity and gas are a fundamental need and PG&E is also working hard to help our customers save money. Early in 2010, PG&E filed the Summer 2010 Rate Relief Application (A.10-02-029) with the California Public Utilities Commission that included an overall electricity rate reduction that took effect before the summer of 2010 and changes to the tiered residential electric rate structure in ways that would reduce costs for our highest use residential electricity customers. This Application was approved by the CPUC and the rate changes became effective on June 1, 2010, providing effective rate relief for these highest use residential electricity customers.

More recently PG&E proposed and received approval for a "rate stabilization adjustment" plan that eliminated a looming rate roller coaster situation where electric rates would have dropped precipitously in January only to be brought back up later in the year.

Current state law mandates that electric utilities in California must charge more per unit of electricity as a residential customer'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 amounts by which rates for the lowest tiers' could increase -- tiers 1 and 2 – and, as a result, those lower tier rates have remained largely unchanged during 2001-2009, resulting in lower tier electricity rates that are 19% lower than in 2001 on an inflation-adjusted basis. That means rate increases during that period fell almost exclusively to the higher tiers.

We are committed to helping limit or reduce costs to our customers, and it is our intent that through the recommendations in this report, PG&E can help customers during these tough times. The June 1, 2010 rate changes resulting from PG&E's Summer 2010 Rate Relief Application reduced prices for usage in the highest residential electricity rate tier category from nearly 50 cents per kWh to approximately 40 cents, and brought our residential electricity rates more closely into alignment with other utilities in the state. This has allowed us to make progress towards distributing electricity costs more equitably among all our customers, and has eliminated some of the "sticker shock" that can occur when a customer's usage crosses into the top rate tier, especially during peak summer months. However, electricity rates for usage in the highest tiers remain very high (for example, the tier 4 rate is over three times as high as the tier 1 rate), and continuing constraints on rates for tier 1 and 2 usage still leave the upper tiers at significant risk of future electricity rate increases. For these reasons, PG&E has proposed additional changes to the residential tier structure in the currently pending Phase 2 of our 2011 General Rate Case, with the goal of affording further reductions to our rates for usage in the highest tiers while also achieving more stability for the upper-tier rates in upcoming years.

In order to manage utility costs and rate increases, PG&E has recommended 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 policy or regulatory mandates. Among these regulatory mandates and requirements that are creating cost pressures on PG&E's electric and gas costs and rates are California's Renewables Portfolio Standard, including legislation and regulations to expand the amount of renewable energy PG&E is obligated to procure;[1] expenditures on public purpose programs mandated by state law; the costs for compliance with greenhouse gas (GHG) emissions regulations and goals under AB 32; the costs of mandated subsidies or set-asides for preferred energy resources, such as distributed generation, combined heat and power, and small renewables under so-called "feed-in" tariffs or "net energy metering;" mandates for considering a requirement to phase-out once-through-cooling for nuclear and non-nuclear powerplants; regulatory mandates to default customers onto particular "dynamic" pricing time-of-use rates whether the customers voluntarily choose the rates or not; and delays in permitting for major utility infrastructure projects, such as new electric transmission facilities.

These legislative and regulatory mandates and policies are all well-intentioned and seek to achieve worthy overall goals. However, to the extent that the mandates and policies add costs to retail electricity and gas rates, or restrict the ability of PG&E and other utilities to manage or mitigate costs, then the Legislature and Commission should periodically review the mandates and policies to ensure that they appropriately balance the benefits to customers with the overall costs of implementation and compliance that customers pay in their monthly bills.

In addition to these cost pressures, 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 review of these measures and issues 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.

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[1] See PG&E comments on RPS legislation, attached to this letter as Appendix 1.

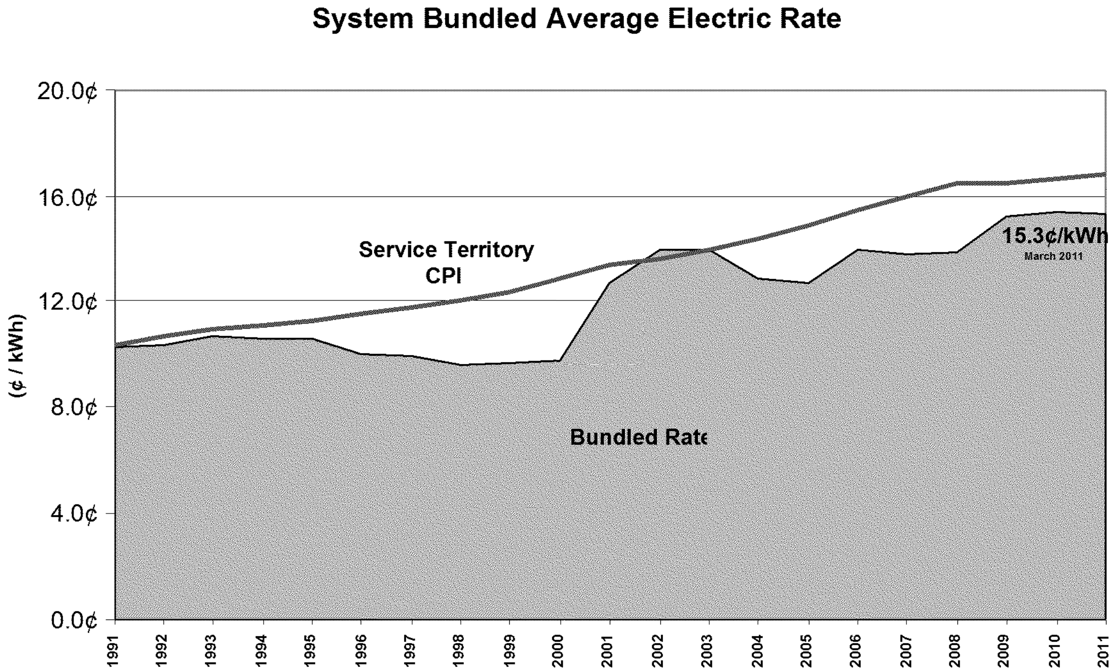
II. Overall Rate Policy

PG&E strives to provide its customers with reasonable rates for gas and electric service. PG&E's overall rate policy is to fully recover the costs of efficiently serving its customers, while considering cost-based pricing, equity within and among customer classes, and public policy objectives.

PG&E understands that its customers value transparency and stability in the rates they are charged for energy. Therefore, PG&E seeks to minimize the impact of rate adjustments made throughout the year. Generally, PG&E requests electric rate changes two to three times per calendar year (January and March, and sometimes October). 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 directives 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 a 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 related to a balancing account over-collection. Similarly, to decrease pressure on customer bills during 2010, PG&E proposed and received CPUC approval to accelerate credits of balancing account over-collections and defer collection of certain approved revenue requirements. PG&E also proposed and received approval for a "rate stabilization adjustment" plan that resulted in a 0.7% net increase from December 2010 and avoided what would have been a 4% decrease in January 2011 followed by a 5% increase over the remainder of the year. These are recent examples of how PG&E and the CPUC can work together to achieve increased predictability and stability for our customer's gas and electricity bills.

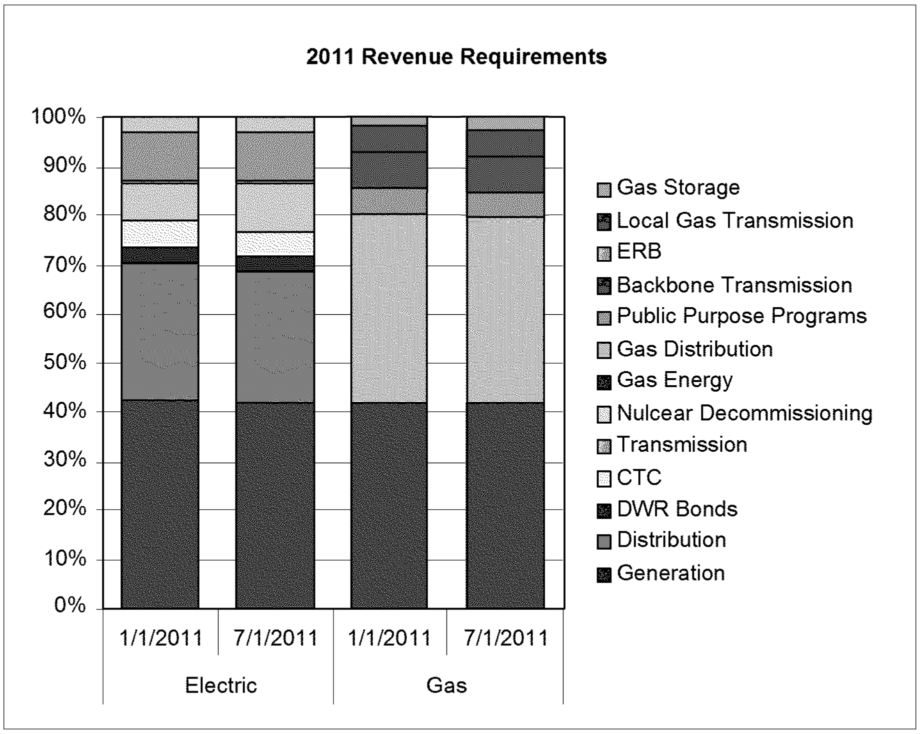
Figure 1. Historic Service Territory CPI vs. System Bundled Average Electric Rate. CPI provided by Economy.com



III. Description of Revenue Requirements (Gas and Electric)

This section summarizes 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. For example, Energy/Generation includes purchased power costs, utility-owned generation, and pension revenue requirements linked to generation, among other items. Relative ranges for each RRQ category as a percent of total authorized 2011 RRQ, and analogous forecast trends for 2011, are provided for each RRQ section. A summary is provided in Figure 2 below. 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 2011 Electric Transmission RRQ divided by Total Authorized 2011 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 2011



Electric

Electric revenue requirements are grouped into the following major rate categories: (1) Energy and Generation, (2) Competition Transition Charge (CTC), (3) Distribution, (4) Department of Water Resources (DWR) bonds, (5) Transmission, (6) Public Purpose Programs, (7) Nuclear Decommissioning, and (8) Energy Revenue Bonds. For reference, an excerpt from the Advice 3727-E-A Annual Electric True-Up filing and December 30, 2010 is provided as Table 1 in the Appendix. The following statements reflect PG&E's expectations as of February 1, 2011, and may change throughout the course of the coming year.

1) Energy and Generation-related electric revenue requirements constitute approximately 42 percent of the total forecast revenue requirement in 2011. (For ratemaking purposes, DWR power costs are treated as a part of the generation rate component.) Energy Resource Recovery Account (ERRA) costs represent roughly 28 percent, DWR power represents -2 percent, and utility-owned generation represents 16 percent of PG&E's total forecasted revenue requirements in 2011. During 2010, generation revenue requirements comprised 50 percent to 52 percent of PG&E's total authorized revenue requirement. The year-over-year change in generation-related revenue requirements reflects large decreases in the costs of energy procurement (ERRA and DWR power) and decreases in undercollections in the energy-related balancing accounts (ERRA, UGBA, and DWR power).

2) Competition Transition Costs revenue requirements constitute approximately 5 percent of the total forecasted revenue requirement in 2011. This represents the above-market cost of procuring energy. In 2010, CTC revenue requirements were about 3 percent of the total revenue requirements. The year over year change in the revenue requirements is a result of higher above market cost driven primarily by lower market benchmark price caused by lower gas prices.

3) Distribution-related electric revenue requirements include the California Solar Initiative and the SmartMeter™ program. The CARE discount has been transferred to the Public Purpose Program revenue requirements where it is recovered through the CARE surcharge. This remaining distribution revenue requirement comprises approximately 27 percent of the total revenue requirements in 2011. In 2010, Distribution revenue requirements were also approximately 25 percent of the total authorized revenue requirements. The increase year-over-year is primarily due to the reinstitution of the CSI revenue requirement and the expected settlement in PG&E's 2011 Test Year General Rate Case.

4) The DWR bond revenue requirements comprise 3 percent of PG&E's forecast 2011 revenue requirement which is the same as in 2010.

5) Transmission-related electric revenue requirements contribute 8 percent to 10 percent of the total forecast revenue requirement in 2011. In 2010, transmission revenue requirements accounted for approximately 6 percent to 8 percent of the authorized total. Investments undertaken by other California utilities and PG&E both contribute to the transmission revenue requirement growth over 2010. 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.

6) Public Purpose Program-related electric revenue requirements include the CARE discount which is recovered through the CARE surcharge. These revenue requirements comprise 10 percent of PG&E's total forecast revenue requirement in 2011. PPP represented about 8 percent of the total during 2010. Growth in Public Purpose Program revenue requirements from 2010 to 2011 is tied to the expansion of the CARE Program. The CARE discount projected for 2011 reflects the increase in forecasted customer discounts due to this expansion in enrollment. In addition, there is a carryover of the CARE shortfall not recovered in 2010. This was due to the CARE surcharge being set on a forecasted CARE shortfall which was much lower than what was actually provided in due to the expansion of CARE enrollment.

7) Nuclear Decommissioning-related electric revenue requirements represented less than 1 percent of PG&E's total authorized revenue requirement during 2010. That level is forecast to remain constant in 2011.

8) Energy Recovery Bond-related electric revenue requirements represent roughly 3 percent of PG&E's forecast revenue requirement in 2011 and will come to the end of their life

during 2012. During 2010, Energy Recovery Bonds comprised between 2 percent to 2.5 percent of the total revenue requirement.

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 3165-G-A Annual Gas True-Up filing on December 22, 2010 is provided as Table 2 in the Appendix. The following statements reflect PG&E's expectations as of February 1, 2011, and may change throughout the course of the coming year due to various internal and external factors.

1) For 2010, energy-related gas revenue requirements represented about 43 percent of the total gas revenue requirements. The revenue requirements are expected to trend upward, consistent with the market price of natural gas. However, the forecasted revenue requirements could range from approximately 36 percent to 46 percent of the total forecast gas revenue requirements in the upcoming 12 months if natural gas prices change by $1 per Decatherm (Dth) from PG&E's forecast.

2) For 2010, distribution-related gas revenue requirements constituted about 38 percent of the total authorized gas revenue requirements. Distribution revenue requirements are expected to trend upward primarily due to the implementation of PG&E's 2011 General Rate Case and SmartMeter program costs. The forecasted revenue requirements could range from 35 percent to 42 percent of the total forecast gas revenue requirements in the upcoming 12 months if natural gas prices change by $1 per Dth from PG&E's forecast.

3) For 2010, Mandated Public Purpose Programs gas revenue requirements, including California Alternate Rates for Energy (CARE) Discount and Self-Generation Incentive Program, and Energy Efficiency represented about 5 percent of the total authorized gas revenue requirements. The forecast revenue requirements constitute approximately 5 percent to 6 percent of the total forecast gas revenue requirements and are expected to trend 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.

4) For 2010, backbone transmission-related gas revenue requirements constituted approximately 7 percent of the total authorized gas revenue requirements. The forecasted backbone transmission revenue requirements will comprise about 6 percent to 8 percent of the total forecast gas revenue requirements in the coming year, and are generally expected to trend slightly downward in 2011 but increase in 2012. Increases in 2012 are driven by replacement of aging facilities and retrofits/replacements for environmental regulations as provided in PG&E's Gas Transmission and Storage Rate Case.

5) For 2010, local transmission-related gas revenue requirements represented approximately 5 percent of the total authorized gas revenue requirements. The forecasted gas revenue requirements will generally contribute 5 percent to 6 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 as provided in PG&E's Gas Transmission and Storage Rate Case.

6) For 2010, gas storage-related revenue requirements contributed about 2 percent of the total gas revenue requirements. Forecasted gas storage revenue requirements comprise approximately 1 percent to 3 percent of the total forecast gas 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 as provided in PG&E's Gas Transmission and Storage Rate Case.

IV. Description of Rates (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 requirements across customer classes and rate tiers also impact the rates experienced by individual customers. Table 1 below provides a summary.

Table 1. Summary of Rate Components for 2011

COMPONENT	**Electric 2011**		**Gas 2011**	
	RRQ $M	**% Range**	**RRQ $M**	**% Range**
Energy / Generation	$5,152	42	$1,367	36-46
Distribution	$3,367	27-28	$1,254	35-42
CTC	$652	5	N/A	N/A
Transmission / Backbone Transmission	$927	8-10	$241	6-8
Local Transmission (Gas)	N/A	N/A	$172	5-6
Public Purpose Programs	$1,194[1]	10	$189[2]	5-6
Gas Storage	N/A	N/A	$52	1-3
Nuclear Decommissioning	$59	0.5	N/A	N/A
DWR Bonds	$389	3	N/A	N/A
Energy Recovery Bond	$405	3	N/A	N/A
Total Authorized Revenue Requirement[3]	$12,144		$3,275	

1. Reflects CARE shortfall of approximately $516M for electric.
2. Reflects CARE shortfall of approximately $110M for gas.
3. As of February 1, 2011. Values are approximated to the nearest million.

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 with the Commission. Historically, aggregate customer sales increased at a pace which largely offset annual increases to revenue requirements. However, in recent years (2009 and 2010), as a result of the economic recession, declining sales has meant that most customers have shouldered a larger portion of revenue requirement increases. The following section discusses the forecast trends for Electric and Gas loads for 2011.

Electric

Although the PG&E service area economy has finally improved, the forecast, as projected by Moody's Analytics, shows an economy that will remain quite soft for 2011. The economy will continue to lose jobs, but not at rates observed over the last three years, and the unemployment rates should finally top out. Real income is projected to grow at nearly 4 percent this year, as job growth in the higher salaried Bay Area expands. With this outlook as a backdrop, PG&E's forecast projects electric sales for 2011 increasing at 1.4 percent relative to 2010 observed sales. This is a bit misleading, however, with 2010 being one of the coolest years in recent memory. Adjusting 2010 observed sales for normal temperatures implies sales growth in 2011 of just 0.6 percent, a rate consistent with the weak economy. Even as the economic recovery gains some traction in 2012, many risks to the recovery remain, and are likely to inhibit what would be a normal expansion in the historical sense. PG&E sales growth are likely to remain modest even in 2012 and beyond.

Electric customer (billings) growth has also been dramatically impacted by the recession. PG&E has added only 18,000 customers over the past 2 years, when adding 60,000 to 80,000 annually was the norm for much of the past decade. For 2011, customer growth will rebound somewhat, with a projected 38,000 customers being added. Thereafter, customer growth will approach more typical values, with about 60,000 customers added annually.

Among the four major electric customer classes (residential, agricultural, industrial, commercial) three are projected to show increased sales in 2011. Although residential sector sales are projected to increase by a seemingly robust 2.4 percent, it should be remembered that this is compared to observed 2010 sales, and as mentioned above, the mild 2010 summer reduced residential demand. Under normal conditions, the residential sales growth rate would likely be ½ to lower. Commercial sales are projected to grow modestly at about ½ percent this year, as vacancy rates remain high and consumers spend carefully. Industrial sales are expected to show fairly robust growth of over 3 percent, but this comes after a steep plunge in industrial usage of 10 percent over the past 2 years. Agricultural sales (primarily groundwater pumping) are expected to decline modestly (about 3 percent) owing to the normal-to-above-normal precipitation levels being experienced during the 2010-2011 wet season

Gas

As described in the Electric subsection above, PG&E's service area economy is expected to remain rather soft through 2011. This will impact both electricity demand (described above) and gas throughput. PG&E's forecast projects 2011 gas sales for all three major gas customer classes - residential, commercial, and industrial - to show modest declines in usage this year. Beyond 2011, residential, commercial, and industrial demand are expected to change very little from 2011 to 2015.

The residential gas demand forecast incorporates real residential rates, the number of households in PG&E's 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 modest customer growth combined with building standards and energy efficiency programs that continue to reduce overall residential usage, residential demand is projected to drop by about 4 percent in 2011. Thereafter, customer growth will tend to offset lower usage per household. 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 high existing commercial vacancy rates, 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 2011 by about 1 percent.

Finally, demand for gas used in electric generation is also expected to be lower in 2011. Many factors drive the volatility in gas demanded for electric generation, including the economy, gas prices, hydroelectric generation capacity, new generation facilities coming online, and nuclear generating capacity. In 2011, however, the main factors impacting electric generation will be the soft economy and the wet winter of 2010-2011 that will likely lead to abundant hydroelectric generation.

V. Management of Electric and Gas Rates and Costs

PG&E is committed to controlling costs and managing rates 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, uncollectible accounts, weather, interest rates, the cost of implementing state mandates, 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. 2011/12 Significant PG&E Rate Initiatives and Changes

Table 3 in the Appendix contains information on PG&E's significant rate initiatives and changes for 2011- 2012. The table has been modified to reflect the currently anticipated rate filing schedule for 2011, and 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 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 on Ratemaking 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 perhaps 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. When a customer reduces their own contribution to cost of service to below avoided costs, the difference shortfall is paid by other customers. Because PG&E's current rate structure recovers a portion of fixed costs via 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 California Legislature and other energy policymakers 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, including 1) the spread in residential tiered rates, and 2) incentives and costs associated with distributed generation.

The most immediate area of concern that should be evaluated over the next 12 months is the statutory mandate for tiered residential electric rate design, where a five "tier" rate structure is employed (although reduced to four tiers with the June 1, 2010 rate changes described in Section 1 of this report). This structure, first put in place by statute 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. Without modification, rates projected for the summer of 2010 were expected to be close to 50 cents per kWh. PG&E has proposed further changes in the currently pending Phase 2 of its 2011 General Rate Case. These changes would reduce the current structure to just three tiers, adjust current baseline quantities, and incorporate a modest monthly customer charge, among other changes, all with the goal of distributing electricity costs more equitably among all our customers. PG&E respectfully requests the Commission's support to make these changes. While legislation was recently passed to allow 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 that legislative changes be considered this coming year to reform the tiered electric rate structure and return the responsibility for reviewing and approving equitable and reasonable electricity rate designs to the CPUC.

Tables and Appendices

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

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	8,986,589	8,986,589
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.

SB_GT&S_0011828

Table 2. Excerpt from Advice 3165-G-A Annual Gas True-Up filing for Rates Effective January 1, 2011.

Pacific Gas and Electric Company		Revised	*Cal. P.U.C. Sheet No.*	28685-G
San Francisco, California	*Cancelling*	Revised	*Cal. P.U.C. Sheet No.*	28412-G
U 39				

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.)

	Amount ($000)					
Description	Core	Noncore	Unbundled	Core Procurement	Total	
BASE REVENUES (Incl. F&U) :						(T)
Authorized GRC Distribution Base Revenue (1)					1,110,089 (R)	
Pension (2)					35,009 (N)	(N)
Less: Other Operating Revenue					(26,023)	
Authorized Distribution Revenues in Rates	1,080,225 (I)	38,850 (I)			1,119,075 (I)	(T)
BCAP ALLOCATION ADJUSTMENTS AND CREDITS TO BASE:						
G-10 Procurement-Related Employee Discount	(1,132) (I)				(1,132) (I)	
G-10 Procurement Discount Allocation	447 (R)	685 (R)			1,132 (R)	
Less: Front Counter Closures	(355)				(355)	
Core Brokerage Fee Credit	(6,583) (I)				(6,583) (I)	
Distribution Base Revenue with Adj. and Credits	1,072,602 (I)	39,535 (R)			1,112,137 (I)	(T)
TRANSPORTATION FORECAST PERIOD COSTS & BALANCING ACCOUNT BALANCES (3):						(T)
Transportation Balancing Accounts	91,716 (R)	15,049 (I)			106,765 (R)	
Self-Generation Incentive Program Revenue Requirement	2,569 (I)	3,911 (I)			6,480 (I)	
CPUC Fee	1,970	1,240			3,210	
ClimateSmart	0	0			0	
SmartMeter™ Project	45,997				45,997	
Winter Gas Savings Plan (WGSP) – Transportation	2,179 (R)				2,179 (R)	
Franchise Fees and Uncollectible Expense (F&U) (on items above)	1,747 (R)	253 (I)			2,000 (R)	
CARE Discount included in PPP Funding Requirement	(110,499)(R)				(110,499)(R)	
CARE Discount not included in PPP Surcharge Rates	0				0	
Transportation Forecast Period Costs & Balancing Account Balances	35,679 (R)	20,453 (I)			56,132 (R)	
GAS ACCORD REVENUE REQUIREMENT (Incl. F&U) (4):						(T)
Local Transmission	120,734 (I)	51,662 (I)			172,396 (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		160,593		240,987	
Gas Accord Revenue Requirement	244,978 (I)	56,836 (I)	168,343		470,157 (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. Prior to 2011, Pension was included in GRC Distribution Base Revenue. Going forward, Pension is shown as its own line item. (N)

(2) D.09-09-020 authorized a $140.5 million total revenue requirement, of which $35 million is allocated to gas distribution. (N)

(3) - The total 2011 SGIP revenue requirement (RRQ) was approved in D.09-12-047. (T)
- 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.
- D.06-07-027 authorized Advanced Metering Infrastructure ("AMI")/SmartMeter™ Project deployment. The gas portion of the adopted 2010 SmartMeter™ RRQ is $46 million. The Phase 1 of the GRC settlement agreement resolves most issues including several related to SmartMeter™. This RRQ amount remains the same as 2010 and will be revised once the Phase 1 GRC decision is issued. (T)
- The Energy Division approved PG&E's AL 3130-G-A to continue PG&E's Winter Gas Savings Program (WGSP). The approved marketing, outreach and administration costs are shown here allocated between transportation and procurement on an estimated basis pending the results of the WGSP. The estimated program credits are collected in rates, resulting in a net zero revenue requirement. (N)(T) (N) (N)

(4) D.10-12-037 authorized PG&E's alternative request in its October 8, 2010 Motion to allow the Gas Accord V revenue requirements, which are to be approved in a subsequent decision, to become effective as of January 1, 2011, even if the Gas Accord V decision is issued after that date. Pursuant to Article 2.3.2, the 2010 Gas Accord IV rates remain in effect on January 1, 2011, plus a two percent escalator for Local Transmission rates and an increase in Local Transmission rates to reflect the negotiated Gas Accord IV rate adjustment for the Line 406 "LT Adder" project. Storage revenues allocated to load balancing are included in unbundled transmission rates. (N) (N)

(Continued)

Advice Letter No:	3165-G-A	*Issued by*	*Date Filed*	December 22, 2010
Decision No.	05-06-029	***Jane K. Yura***	*Effective*	January 1, 2011
		Vice President	*Resolution No.*	
2C18		*Regulation and Rates*		

Table 2 (continued). Excerpt from Advice 3165-G-A Annual Gas True-Up filing for Rates Effective January 1, 2011.

Pacific Gas and Electric Company *San Francisco, California* U 39		Revised	*Cal. P.U.C. Sheet No.* 28686-G
	Cancelling	Revised	*Cal. P.U.C. Sheet No.* 28413-G

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	Core	Noncore	Unbundled	Core Procurement	Total	
	Amount ($000)					
ILLUSTRATIVE CORE PROCUREMENT REVENUE REQUIREMENT (5):						(T)
Illustrative Gas Supply Portfolio				1,174,638 (R)	1,174,638 (R)	
Interstate and Canadian Capacity				178,209 (R)	178,209 (R)	
WGSP – Procurement – Residential				2,122 (R)	2,122 (R)	
F&U (on items above and Procurement Account Balances Below)				16,370 (R)	16,370 (R)	
Backbone Capacity (incl. F&U)	(61,697)			61,697	0	
Backbone Volumetric (incl. F&U)	(18,698)			18,698	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)				6,583 (R)	6,583 (R)	
Procurement Account Balances				(3,984) (R)	(3,984) (R)	
Illus. Core Procurement Revenue Requirement	(124,245)			1,498,183 (R)	1,373,938 (R)	
TOTAL GAS REVENUE REQUIREMENT (without PPP) IN RATES	1,229,014 (R)	116,824 (I)	168,343	1,498,183 (R)	3,012,364 (R)	
PUBLIC PURPOSE PROGRAM (PPP) FUNDING REQUIREMENT (F&U exempt) (6):						(T)
Energy Efficiency (EE)	70,052 (I)	7,798 (I)			77,850 (I)	
Low Income Energy Efficiency (LIEE)	57,845 (I)	6,439 (I)			64,284 (I)	
Research, Demonstration and Development (RD&D)	6,586 (R)	3,762 (R)			10,348 (R)	
CARE Administrative Expense	1,128 (I)	776 (I)			1,904 (I)	
BOE and CPUC Administrative Cost	181 (R)	103 (R)			284 (R)	
PPP Balancing Accounts	2,268 (I)	(4,568) (R)			(2,300) (I)	
CARE Discount Recovered from non-CARE customers	65,447 (R)	45,052 (I)			110,499 (I)	
Total PPP Funding Requirement in Rates	203,507 (I)	59,362 (I)			262,869 (I)	
TOTAL GAS REVENUE AND PPP FUNDING REQUIREMENT IN RATES	1,432,521 (R)	176,186 (I)	168,343	1,498,183 (R)	3,275,233 (R)	
TOTAL AUTHORIZED GAS REVENUE AND PPP FUNDING REQUIREMENT	1,432,521 (R)	176,186 (I)	168,343	1,498,183 (R)	3,275,233 (R)	

(5) 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 is an annual illustrative amount. Actual gas commodity costs change monthly. WGSP costs, approved in AL 3130-G-A, will be recovered in residential rates effective April 1, 2011. (T) I (T)

(6) 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.09-10-027, CARE annual administrative expense adopted in D.08-11-031, and excludes F&U per D.04-08-010. (T)

(Continued)

Advice Letter No:	3165-G-A	*Issued by*	*Date Filed*	December 22, 2010
Decision No.	05-06-029	***Jane K. Yura***	*Effective*	January 1, 2011
		Vice President	*Resolution No.*	
3C17		*Regulation and Rates*		

Table 3. Key Filings Effecting Rates

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation date	Requested $ Amount			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2011 RRQ*	2012 RRQ*			
Q3 2009									
Wildfire Insurance Recovery	A. 09-08-020	Aug	N/A	N/A	N/A	N/A	Develop regulatory proposal for recovery of uninsured claims costs arising from wildfires	N/A	N/A
Q1 2010									
MRTU Cost Recovery - ERRA 2009 Compliance Filing	A.10-02-012	Feb	1/1/12	60	18	-	Request for recovery of costs PG&E incurred through December 31, 2009, to comply with the mandated Market Redesign and Technology Upgrade (MRTU) initiatives	Electric	Energy/ Generation, Competition Transition Charge (CTC)
Rate Design Window 2010 (Peak Time Rebate)	A.10-02-028	Feb	5/1/11	33	0	5	Requests approval for PTR program that provides incentives for customers to respond to price signals on event days when demand is expected to be high	Electric	Energy/ Generation
General Rate Case (GRC) 2011 Ph II - Rate Design	A.10-03-014	Mar	5/1/11	-	-	-	PG&E's electric marginal cost, revenue allocation and rate design proposals for 2011. Does not affect Revenue Requirements, but effects rates	Electric	PPP, Distribution, Energy/ Generation, Competition Transition Charge (CTC)
Q3 2010									
TO 13 (TY 2011)	ER10-2026-000	July	3/1/11	N/A	1,026	-	Annual transmission filing with FERC	Electric	Transmission
Default Residential Rate Programs (Peak Day Pricing)	A.10-08-005	Aug	TBD	141	-	-	In compliance with D.08-07-045, Ordering Paragraph (OP) 8, by August 9, 2010, PG&E needs to file an application proposing a default Critical Peak Pricing (CPP) rate for residential customers, subject to their ability to opt-out of the CPP rate	Electric	Energy/ Generation
Pumped Storage Project	A.10-08-011	Aug	1/1/12	33	-	7	Requests cost recovery for costs in support of the feasibility studies and the associated application for federal hydropower project licensing	Electric	Generation
2011 Gas Transmission & Storage (GT&S) Rate Case (Settlement)	A.09-09-013	Aug	1/1/11	N/A	514	541	The 2011 GT&S rate case sets the rates, terms and conditions of service for PG&E's gas transmission (backbone and local transmission) and storage business for the period 2011 to 2014. Proposed settlement filed on September 20, 2010; actual results may differ from settlement	Gas	Local Transmission, Backbone Transmission, Gas Storage

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation date	Requested $ Amount			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2011 RRQ*	2012 RRQ*			
Q4 2010									
2011 GRC Phase I (Settlement)	A.09-12-020	Oct	1/1/11	N/A	5,977	6,157	Request approval of electric and gas distribution and generation base revenues to recover Operations & Maintenance and Administrative & General expenses, depreciation, and taxes and provide a return on invested capital for the test year (i.e., 2011) and the attrition years (i.e., 2012 and 2013 assuming a normal three-year GRC cycle). Proposed settlement filed on October 15, 2010	Electric/ Gas	Distribution, Generation, PPP
Silicon Valley Technology Center	A.10-11-002	Nov	1/1/12	36	-	18	Application seeking approval to support a photovoltaic (PV) Manufacturing Development Facility in San Jose, California	Electric	Distribution
Diablo Canyon Power Plant License Renewal (Settlement)	A.10-01-022	Nov	1/1/15	80	-	-	Requests authority to recover in rates the costs associated with obtaining the federal and state approvals required to seek a 20 year license renewal for Diablo Canyon Power Plant. Proposed settlement filed on November 16, 2010	Electric	Energy/ Generation
Q1 2011									
General Rate Case (GRC) 2011 Ph III - Dynamic Pricing	A.10-03-014	Jan	1/1/12 (RTP) 7/1/12 (RCES)	50	-	3	The request includes $2.7 million in revenue requirements for new voluntary Real Time Pricing rate options, and $0.3 million in revenue requirements for Revised Customer Energy Statement	Electric	PPP, Distribution, Energy/ Generation, Competition Transition Charge (CTC)
ERRA 2010 Compliance Filing - MRTU Cost Recovery	A.11-02-011	Feb	1/1/12	19	23	21	Request for recovery of costs PG&E incurred through December 31, 2010, to comply with the mandated Market Redesign and Technology Upgrade (MRTU) initiatives as well as revenue requirements for 2011 and 2012 for MRTU Release 1	Electric	Energy/ Generation, Competition Transition Charge (CTC)
Demand Response Program Years 2012-2014	A.11-03-001	Mar	1/1/12	234		77	Per D.09-08-027, PG&E will file its application to support Demand Response programs and expenses for the 2012-14 program cycles by January 31, 2011	Electric	Distribution
Q2 2011				-	-	-	-		
Energy Resource Recovery Account (ERRA) 2012 Forecast	TBD	Jun	1/1/12	TBD			Annual filing	Electric	Energy/ Generation, Competition Transition Charge (CTC)

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Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation date	Requested $ Amount			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2011 RRQ*	2012 RRQ*			
Winter Gas Savings Program (2011-2012)	TBD	Jun	9/1/11	TBD			To request cost recovery approval for WGSP	Gas	Energy (gas procurement), Distribution
Core Procurement Incentive Mechanism Shareholder Award	TBD	TBD	TBD	TBD			To request shareholder award achieved through CPIM performance (Nov 2009 - Oct 2010)	Gas	Energy (gas procurement)
Pipeline 2020	TBD	TBD	TBD	TBD			Application requesting a program to modernize PG&E's gas transmission infrastructure	Gas	Local Transmission, Backbone Transmission
Q3 2011				-	-	-	-		
FERC - TO14 (TY 2012)	TBD	Jul	3/1/12	TBD			Transmission costs recovered through FERC	Electric	Transmission
Annual Electric True-Up (AET) 2012	TBD	Sep	1/1/12	TBD			Annual filing	Electric	Transmission, PPP, Distribution, Energy/ Generation, DWR, CTC, ERB
Q4 2011				-	-	-	-		
FERC TRBA/ECRA/RSBA Filing	TBD	Oct	1/1/12	TBD			Transmission costs recovered through FERC	Electric	Transmission
Public Purpose Program Surcharge Gas Rate Filing 2011 - Advice Letter	TBD	Oct	1/1/12	TBD			Annual filing	Gas	Public Purpose Programs/Mandated Programs
SB 695 Res Rate Change (T1 & T2) Advice Letter	TBD	Nov	1/1/12	TBD			Annual increase to residential rates for Tier 1 and Tier 2 in compliance with SB695	Electric	Distribution, Energy/ Generation
Energy Resource Recovery Account (ERRA) 2012 Forecast - Update	TBD	Nov	1/1/12	TBD			Annual filing	Electric	Energy/ Generation, Competition Transition Charge (CTC)
Annual Gas True-Up (AGT) 2012	TBD	Nov	1/1/12	TBD			Consolidation of gas transportation rate changes authorized by CPUC	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage

Filing Name	Proceeding Reference	Filing Date	Requested/ Expected Implementation date	Requested $ Amount			Description	Impacted Rate	Impacted Rate Component
				Total Cost	2011 RRQ*	2012 RRQ*			
Annual Gas True-Up (AGT) 2012 - Advice Letter Update	TBD	Dec	1/1/12	TBD			Consolidation of gas transportation rate changes authorized by CPUC	Gas	Distribution, Local Transmission, Backbone Transmission, Gas Storage
Annual Electric True-Up (AET) 2012 - Advice Letter Update	TBD	Dec	1/1/12	TBD			Annual filing	Electric	Transmission, PPP, Distribution, Energy/Generation, DWR, CTC, ERB
FERC TACBA Filing	TBD	Dec	3/1/12	TBD			Transmission costs recovered through FERC	Electric	Transmission

Appendix 1

Pacific Gas and Electric Company.

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SENATE FLOOR ALERT
SBX1 2 (Simitian, Kehoe, Steinberg) - OPPOSE UNLESS AMENDED

MISSES CRITICAL OPPORTUNTIES TO ENSURE COST PROTECTIONS

Pacific Gas and Electric Company (PG&E) opposes SBX1 2 unless amended to set clear rules and provide adequate tools that will ensure cost protections for our customers. PG&E supports three specific changes to the bill to mitigate costs for our customers and provide a successful framework to achieve our aggressive clean energy goals.

1. **RECs: Out-of-state flexibility and consistent rules will create market certainty.**

- SBX1 2: Out-of-state limits on use of unbundled renewable energy credits (RECs) and firmed and shaped deliveries lack procurement flexibility and exacerbate seller's market.
- Result: Increased costs due to a constrained renewables market with few options to mitigate uncertainty of long-term in-state development.
- SBX1 2: Establishes impractical and needlessly complex limits on west-wide renewables and disregards rules recently established by the California Public Utilities Commission (CPUC).
- Result: Changing the rules yet again in such a short period will create significant market disruption and jeopardize the ability of renewable projects to secure financing.
- **PG&E supports clear and consistent rules that mirror the recent CPUC action where no more than 25 percent of the annual RPS requirement can come from renewable energy not directly connected to a California balancing authority or delivering energy in real time to California.**

2. **Banking: Incentivize early action and allow customers to get full value of RPS deliveries, regardless of the term of the contract.**

- SBX1 2: Extra deliveries above the RPS target carry forward only if the extra deliveries come from contracts no less than 10 years in duration.
- Result: Our customers will pay the premium for RPS energy, but then it can't be used to meet the compliance requirement.
- Result: SBX1 2 picks winners and losers by discriminating between existing generators who often sign shorter contracts and new developers seeking long-term contracts to attain project financing.
- **PG&E supports banking of in-state contracts of at least five years in duration.**

3. **Set realistic targets that recognize the "lumpy" nature of renewables development.**

- SBX1 2: Requires the CPUC to set progress goals in-between the established targets ignoring the "lumpy" nature of renewables procurement and creating a new accounting scheme.
- Result: CPUC focuses its resources on accounting scheme rather than execution of the program.
- **PG&E recommends that the targets be modified to reflect those adopted in the California Air Resources Board's 33% Renewable Energy Standard on September 23, 2010.**

A WELL DESIGNED RPS PROGRAM WILL RECOGNIZE EARLY ACTION AND SOLIDIFY CALIFORNIA'S NATIONAL LEADERSHIP ON CLEAN ENERGY RATHER THAN CONTINUING THE CYCLE OF EXCUSES. ABSENT AMENDMENTS TO ACHIEVE THESE GOALS, WE ASK FOR YOUR "NO" VOTE ON SBX1 2.

2/22/11