California Energy Regulatory Update, July 2004

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PG&E

A04-06-024. PG&E GRC Phase II

Normally, Phase 2 of a General Rate Case (GRC) is limited to electric revenue allocation and rate design. Phase 1 deals with revenue requirements (how much money the utility is to collect). The CPUC approved PG&E's Phase 1 revenue requirements on May 27, 2004, by D.04-05-055. However, during Phase 1 of PG&E's 2003 Test Year GRC Application No. (A.) 02-11-017, in D.03-04-019 the CPUC ordered that Phase 2 of PG&E's GRC would address electric marginal costs as well as revenue allocation and rate design. In layman's terms, Phase 1 decides how big the pie is, Phase 2 decides how to cut it into pieces (who is responsible for paying for what portion).

PG&E's rate design proposals include: 1) reducing the number of commercial, agricultural and industrial rate schedules and options, particularly where participation is relatively low; 2) eliminating complex rate design elements such as agricultural demand charge ratchets and rate limiters on other rate schedules; and 3) redefining or clarifying the applicability of agricultural rates.

Here's a global overview of PG&E's application.

PG&E's 2003 GRC Phase 2 Illustrative Revenue Allocation Results
(Dollars in thousands)

Class and Service	Change in Bundled Revenues	Percent Change in Bundled Revenues	Change in Direct Access Revenues	Percent Change in Direct Access Revenues
Residential	$444,192	12.2%	$401	5.4%
Small Commercial	$7,625	0.6%	$855	12.2%
Medium Commercial	($226,122)	-12.5%	($2,043)	-4.6%
Large Commercial	($128,975)	-12.4%	($9,873)	-7.0%
Streetlights	($1,325)	-2.3%	N/A	N/A
Standby	$4,553	13.3%	N/A	N/A
Agriculture	$7,078	1.5%	($183)	-8.5%
Large Industrial	($92,129)	-8.6%	($4,054)	-2.0%
System Total	$14,897	0.2%	($14,897)	-3.7%

Here is the schedule proposed by PG&E in their application. The final schedule will be set after the Pre-hearing conference.

Thursday, August 19, 2004	**Prehearing Conference**
Monday, November 22, 2004	**Office of Ratepayer Advocates files testimony**
Monday, January 3, 2005	**Intervenors file testimony**
Friday, March 4, 2005	**Rebuttal testimony filed**
Monday, March 28, 2005	**Evidentiary hearings begin**
Friday, April 15, 2005	**Evidentiary hearings end (allows three weeks)**
Friday, May 13, 2005	**Concurrent Opening Briefs filed**
Friday, June 3, 2005	**Concurrent Reply Briefs filed**
Monday, August 29, 2005	**ALJ Issues Proposed Decision**
Monday, September 19, 2005	**Initial Comments Filed – Draft Decision**
Monday, September 26, 2005	**Reply Comments Filed – Draft Decision**
Thursday, September 29, 2005	**Commission Final Decision**

I've provided a overview of PG&E's rate proposals by customer class in an attachment to this report.

Bankruptcy or Piggy Bank?

Remember the $83 million in bonuses that PG&E execs got earlier this year while the company was in bankruptcy? Well, in July PG&E handed out an another $89 million in bonus money to these same execs. Entering in to and emerging from bankruptcy was quite profitable for them. PG&E ratepayers will be paying increased rates for approximately the next 10 years.

The millions given to 17 senior managers in January were retention bonuses, ostensibly to keep these valuable people with the company. The millions given on July 9 to the same 17 execs , as well as to about 6,500 other managers and nonunion employees, were performance bonuses. Bob Glynn, the chairman of the PG&E, received a bonus of $17 million in January. He got a mere second bonus of $1.7 million. That's on top of his base salary last year of $1.05 million. Gordon Smith, PG&E's chief executive, received a January bonus of $10 million, got an additional $906,000. His base salary last year was $735,000. Other PG&E bonuses in July include Tom King, senior vice president for utility operations ($519,000); Dan Richard, senior vice president for public affairs ($235,000); Roger Peters, chief counsel ($228,000); and Kent Harvey, chief financial officer ($225,000).

Too Much Demand – Conservation Programs Closed

PG&E has announced that its residential rebate programs are closed for the rest of this year. Rebates have been available for 30 different types of energy efficiency products, including air conditioners, dishwashers, clothes washers, pool pumps and high performance dual paned windows. Only two remain open, lighting products and refrigerator recycling.

PG&E has received 60,000 rebate applications from its residential customers since December 2003. The utility is still processing several thousand qualified applications, but estimates the applications it has received to date will add up to a total of at least $10.25 million, the amount approved by the California Public Utilities Commission (CPUC) for residential rebates. Applications are processed on a first-come first-serve basis until the money is used up.

PG&E will reopen its residential rebate program again in January 2005.

Seeks Renewables

Highlights of the PG&E renewables solicitation: 10-20 year contracts starting in 2005 or later, have to choose one type: 1)As-Available 2) Baseload 3) Peaking 4) Dispatchable, must bid 1 MW or greater, bidder must provide bid deposit of $5/kW

Here's the schedule for the PG&E renewables RFP:
July 15 PG&E issues Request for Offers
July 26 Participants file Notice of Intent to Bid
July 28 Pre-Bid Conference
August 23 Deadline for Participants to Submit Bids
September 29 PG&E selects Shortlist of Bids; Consults with PRG
November 29 PG&E concludes negotiations with Shortlisted Bidders; Consults with PRG
December 6 PG&E & Participants execute PPAs subject to Regulatory Approval
December 17 PG&E submits PPAs for Regulatory Approval

Here's the steps for participation:
1. Online Registration. Participants may register at the RFO website: www.pge.com/renewableRFO. Registering will establish the Participant on PG&E's notice list and insure that Participant receives timely announcements andupdates.
2. Notice of Intent to Bid. Participants are requested to submit Attachment C by July 26 with basic project information and an RSVP to the Pre-Bid Conference.
3. Pre-Bid Conference. PG&E held a Pre-Bid Conference at the following time on Wednesday, July 28th, in San Francisco.
4. Offer Submittal Deadline. Participant's offer must be submitted by the deadline and include all the documents. Submittals must be tendered electronically and in hard copy. Deadline: Monday, August 23, 2004, 2:00 p.m. (PPT)
5. PG&E Selects Shortlist. Consults with PRG. PG&E intends to select a Shortlist of Offers for further negotiations. The shortlist and results of subsequent negotiations will be shared with PG&E's PRG. Participants who have been selected for the Shortlist will be required to execute a Confidentiality Agreement in the form attached to the RPS Solicitation Protocol Agreement (Exhibit 1 to Attachment A) agreeing to keep confidential the terms discussed during the course of negotiating the final Agreement.

6. CPUC Releases the Market Price Referents (MPR). The MPR will be used to calculate how much of Participant's price will be paid directly by PG&E under the PPA and how much, if any, will be paid as Supplemental Energy Payments ("SEP") by the utilities' Public Goods Charge account, administered by the California Energy Commission.
7. PG&E and Shortlisted Participants Finalize Agreements. The final Agreements will be shared with the PRG.
8. PG&E and Final Participants Execute PPAs. The effectiveness of the contracts are subject to CPUC Approval and any other conditions precedent set forth in the particular Agreement.
9. PG&E Submits PPAs for Regulatory Approval.

SCE

New Conservation Programs Approved

THE CPUC approved several modifications to existing SCE conservation programs and adopted several new (but in actuality – old) programs. Edison's proposal to reopen the "20/20" program was adopted. This program allots customers a 20 percent bill credit for reducing peak consumption by 20 percent compared to the same month the previous summer. Under the 20/20 program, customers receive a 20 percent bill credit, applied to on-peak energy and demand. To receive the credit, they must reduce their average daily on-peak electricity usage by at least 20 percent in a summer month this year, compared to the same month last year.

Edison will eliminate a requirement that customers who participate in the "critical peak pricing" tariff achieve at least a 3 percent reduction in power use in order to qualify for bill protection.

$73 Million Rate Hike

Edison will raise its electric rates $73 million, or about 2.6 percent more than its current base-rate revenue of $2.74 billion, the CPUC ruled. Edison would get less than the $251 million increase it originally asked for, but more than the $15 million rate hike that draft decisions by Commissioner Carl Wood and Administrative Law Judge Mark Wetzel would have provided. The decision adopts a "post-test-year-ratemaking" mechanism for Edison to adjust the authorized revenue requirement for 2004 and 2005, and allows Edison to recover the costs of refueling and maintenance outages at the San Onofre Nuclear Generating Station. The decision approves revenue increases including $16 million more for information technology expenses and capital costs; almost $11 million more for Edison's real-time energy metering program (get ready, it's coming); nearly $2 million more for transmission and distribution operation and maintenance expenses; and $2.5 million more for economic and business development activities.

The CPUC will decide how the rate hike will be divided among customer classes in a second phase of Edison's general rate case (see similar discussion under PG&E).

SDG&E

Wins Approval Of Transmission Line

The CPUC granted SDG&E's request for a Certificate of Public Convenience and Necessity (CPCN) to add a electric transmission line to help ease the electricity congestion in the San Diego area. The commission's action clears the way for SDG&E to begin construction of a new 230,000-volt (230 kV) electric transmission line along its existing right-of-way from its Miguel substation in the southeast region of San Diego County to its Mission substation in Mission Valley.

Long-Term Energy Resource Plan

SDG&E filed the first annual update to its long-term resource plan. The plan calls for accelerated purchases of renewable energy, such as wind and solar power, a new transmission line in the 2010 time frame, and additional generating plants in subsequent years. The filing notes that recent approval of new generation resources and SDG&E's increase the amount of renewable power it delivers to customers will provide San Diego with adequate energy supplies until 2011. At that time, growth in energy needs, coupled with the expiration of long-term energy contracts signed by the state, will require additional generating plants as part of the overall mix of new resources.

SDG&E has issued a request for offers to supply additional renewable energy resources. Currently, SDG&E has contracts to supply approximately 6 percent of its customers' energy needs with renewable energy by 2010.

Sierra Pacific

$42 Million Rate Increase

The Public Utilities Commission of Nevada authorized Sierra Pacific Power Co. of Reno to recover $42 million in deferred expenses for fuel and purchased power without any disallowance for imprudence. At the commission's meeting July 7, PUCN Chair Don Soderberg rejected Sierra's request to include in its authorized income taxes the interest charges it will earn from customers while recovering the funds.

Sierra rates will increase 4.4 percent overall starting July 15, but those are only the base tariff energy rates (BTER), the part of rates designed to reflect the cost of fuel and power going forward. The typical residential customer's bill will rise 3.4 percent, or $2.80 in an average month.

In April 2005, the amortization period will end for two earlier deferred energy rate cases, and Sierra will start collecting the $42 million over the next 27 months. The result will be a decrease of 1.2 percent, or about $1, on a typical residential customer's monthly bill.

CPUC

I.00-11-001 Transmission Proceeding

See Procurement Proceeding for updates on new transmission lines and needs. The ISO did approve a new transmission line into the Tehachapi area to access the growing wind energy development in the area.

R04-04-003 Coordination Proceeding

This new proceeding functions as a "case-management umbrella" under which the commission will coordinate various pieces of utilities' long-term procurement plans under review in the following eight proceedings:

? Community-choice aggregation [R03-10-003]
? Demand response [R02-06-001]
? Distributed generation [R04-03-017]
? Energy efficiency [R01-08-028]
? Avoided costs and QF pricing [to be established]
? Renewables portfolio standard[to be established]
? Transmission assessment process [R04-01-026]
? Transmission planning [I00-11-001].

Comments were received this month on the adequacy of utility long term resource plans.

R04-04-026 New Renewables Proceeding

See Procurement Proceeding for updates on renewables.

R04-03-017 Distributed Generation

Comments were received in response to the ALJ's Ruling Requesting Comments on Energy Division Recommendations to Improve the Self Generation Incentive Program and Implement AB 1685.

Direct Access R02-01-011

Continuing to argue over how much responsible for stranded costs direct access customers are responsible for.

DWR Revenue Requirements A.00-11-038

Both a draft decision by Administrative Law Judge Peter Allen and an alternate decision by Commissioner Loretta Lynch would reject a settlement agreement reached by Pacific Gas & Electric, Southern California Edison and The Utility Reform Network. Instead, the decisions would keep intact the CPUC's current method of calculating variable costs of long-term power contracts signed by the California Department of Water Resources. PG&E and Edison each are responsible for 43.75 percent and San Diego Gas & Electric responsible for 12.5 percent of DWR contract costs. The allocation methodology is for 2004 and the remaining term of the contracts, through 2013. The proposed settlement would have allocated 43.6 percent of DWR contract costs to PG&E, 42.6 percent to Edison and 13.8 percent to SDG&E.

Utility Procurement R.01-10-024

Some of the highlights of long-term resource-adequacy plans filed with the CPUC July 9:

- Southern California Edison's plan to severely limit the length of power-purchase agreements. It proposes to sign only contracts with a duration of three years. Edison wants to spend $237 million a year on energy efficiency and expects to make its portfolio 20 percent renewable by 2007.

- Pacific Gas & Electric wants 50 percent of new generation through contracts and 50 percent through utility ownership of projects developed by others. New energy-efficiency programs would cost the utility $1 billion in the next decade. PG&E has no plans to accelerate green power procurement in advance of the state-mandated goal of a 20 percent renewables portfolio by 2017, but assumes that by 2010 the percentage will be met by renewables and repowering existing wind projects.

- San Diego Gas & Electric's strategy is to make 20 percent of its portfolio renewable energy by 2007 and reach 24 percent by 2014. The utility plans to spend $118 million in the next two years on energy efficiency then continue with the current level of funding.

PG&E does expect to buy 600 megawatts from an independent supplier under a long-term contract by 2008. Edison and SDG&E have already committed to three new power plants, of which the utilities will own two.

Under state policy, the utilities must first pursue programs to improve energy efficiency and new meters that allow customers to reduce demand when supplies get short and prices rise. They also must get 20% of their supplies from renewable resources by 2017. Finally, they can turn to traditional fossil-fuel fired power plants, but they are supposed to mix that up between their own new plants and contracts with merchant power companies.

Demand side programs R.02-06-001

Here's what happened this month.

- Workshops on Energy Division Workshops Performance Incentives and Measurement and Evaluation Protocol
Reply Comments on Report July 9.
- Workshops on appropriate utility avoided costs:
Post-Workshop comments July 16
Post-Workshop reply comments July 30
- Meetings on 2005 programs: July 13, 2004 in San Francisco, July 27 in Sacramento. There will be one on August 17 in San Francisco, and a final meeting on September 14 in Sacramento.

R.03-10-003 Community Choice Aggregation

Interested parties are in the process of filing brief and replies to briefs. The Commission plans to address operational and implementation issues before the end of the year.

August 2004 - ALJ draft decision in Phase 1 Final Commission order in Phase 1
September 2004 – Final Commission Order
October 2004 - Prehearing Conference on Phase 2 issues

Water Agency Generation R03-09-029

The PHC was January 8th. Awaiting a Commission ruling.

Rural Phone Service Expanding Phone Service in Rural Communities (AB 140 implementation project)

On June 9, the CPUC approved funding to assist in providing telecommunications services to these areas that are currently without telephone service: the Yurok Tribe in Humboldt County in the amount of $2,500,000; the community of Iowa Hill in Placer County in the amount of $1,834,900; and Trinity County in the amount of $2,500,000. **Local governments still have time to request funding for services.** Applications for next fiscal year (July 2004 through June 2005) will be accepted from July 1, 2004, to August 31, 2004. Contact Mary Jo Borak at 415-703-1879 or via e-mail at: bor@cpuc.ca.gov. More information: http://www.cpuc.ca.gov/static/industry/telco/public+programs/rural/index.htm

CEC

Updates Power-Plant Projects

The CEC updates its estimates on new power plant operations in its June 30 report.

Calpine Corp.'s 750 MW Pastoria project The on-line date was listed as June 2005. Phase I of the project (259 MW) is now scheduled to come on line this November. Phase II (500 MW) has an estimated commercial operation date of July 2005. Both phases have been under construction since June 2001 in Kern County.

Calpine's 570 MW Otay Mesa project in San Diego on-line date has been moved from July 2006 to January 2008.

FPL Energy's 1,120 MW Tesla project in Alameda County is now on hold.

Modesto Irrigation District's 95 MW Ripon project on-line date has been moved from April 2005 to October 2005, Construction on this San Joaquin County facility began this month.

San Francisco's 145 MW peaker project on-line date has moved up from April 2007 to June 2006.

ISO

String of Record Demands

For the third day in a row, Californian set a new record peak demand for electricity usage; 44,360 megawatts was set Wednesday, July 21, at 4:18 p.m. The July 20 record peak demand was 44,330 megawatts, breaking the previous record of 43,609 megawatts, which was set July 12, 1999. On Monday, July 26th, the ISO declared a Power Watch day, with a predicted demand of 46,252 MW. Thankfully, cooler weather arrived and we didn't hit this level. We'll have a hard time meeting these levels of demand during the rest of this summer, due to lack of available generation.

Begins Posting Transmission-Outage Information

The Cal ISO has started posting daily listings of transmission outages on a secure Web site available only to its market participants. The posting of the transmission outages occurs daily at 3 am, and includes the name of the facility, the date and time it is due to be out and to return to service, the line's voltage, and a brief description of the reason for the outage. The information was first posted July 6.

WAPA Picks SMUD

The Western Area Power Administration has selected the Sacramento Municipal Utility District to host its sub-control operations for the Sierra Nevada region when its current contract with Pacific Gas & Electric expires next year. WAPA picked SMUD over the California Independent System Operator.

Under the existing contract, PG&E acts as the interface with Cal-ISO. That contract will expire at the end of the year, and SMUD will take over the duties on January 1, 2005. WAPA plans to make its 230 KV system a sub-control area beginning in 2005. The agency will schedule power deliveries, match its generation and load, provide reserves and frequency support to meet reliability criteria, and submit generation schedules to SMUD as the host control area. WAPA will manage net power flows at the sub-control area interconnection points.

WAPA said that it based its decision on five criteria: flexibility, durability, certainty, operating transparency and cost-effectiveness. One big hangup was under the ISO's rules changes could be made to the agreement unilaterally. The SMUD contract cannot be changed without the agreement of both parties.

RURAL INFO

$22.8 Million For Farmers, Ranchers And Small Business

The Department of Agriculture has announced the availability of approximately $23 million in grants that will support President Bush's energy plan to develop renewable energy systems and promote energy efficiency improvements. The Renewable Energy Systems and Energy Efficiency Improvements program was created as part of the 2002 Farm Bill to assist farmers, ranchers, and rural small businesses develop renewable energy systems and make energy efficiency improvements to their operations. In 2003, the Bush Administration invested $21.7 million to assist 114 applicants from 24 states develop or improve wind power, anaerobic digester, solar, ethanol and other bioenergy relate systems or energy efficiency improvements.

Applicants for the Renewable Energy Systems and Energy Efficiency Improvements program must be agricultural producers or rural small businesses, U.S. citizens or legal residents, and have demonstrated financial need. Rural Development grant funds may be used to pay up to 25 percent of the eligible project costs. Eligible projects include those that derive energy from a wind, solar, biomass, or geothermal source, or hydrogen derived from biomass or water using wind, solar, or geothermal energy sources. Applications must be completed and submitted with a postmark no later than 75 days from the May 5, 2004 Federal Register publication of the notice of funding availability. Detailed information about program requirements and information on how and where to apply is included in the funding notice. Award will be made on a competitive basis for the purchase of renewable energy systems and to make energy improvements

DOE and USDA Awards $25 Million Biomass Research and Development

T he Department of Energy (DOE) and the Department of Agriculture (USDA) announced the selection of 22 projects that will receive $25,480,628 for the Biomass Research and Development Initiative. Including the cost sharing of the private sector partners, the total value of the projects is nearly $38 million. The funds will be used for biomass research, development and demonstration projects.

The joint grant program is part of the Administration's effort to increase America's energy independence through the development of additional renewable energy resources from the agricultural and agroforestry sectors. In December, 2003, President Bush signed the Healthy Forest Restoration Act, which was aimed at reducing forest fire risks by making productive use of thinnings from forest lands. These efforts will yield cellulosic materials in the form of brush and small diameter trees that could be converted into multiple forms of fuel. The new processing facilities resulting from this increased demand are supposed to help stimulate rural communities and economies.

Here are the California winners:

- Membrane Technology and Research, Inc. (Menlo Park, Calif.) – BioSep: A New Ethanol Recovery Technology for Small-Scale rural Production of Ethanol from Biomass - $1,032,045
- Watershed Research and Training Center (Hayfork, Calif.) - Hayfork Biomass Utilization and Value Added Model for Rural Development - $503,400
- Electric Power Research Institute (Palo Alto, Calif.) – Small-scale, Biomass Fired Gas Turbine Plants Suitable for Distributed and Mobil Power Generation - $241,933

Low Income Limits Increased

The income limits have increased for all CPUC-authorized consumer discount programs. Consumers who earn a little more than last year's income limits may now be eligible and local government officials may want to remind their constituents to contact their utilities to apply. Programs include discounts on the monthly utility bills for low-income customers and for families with low to middle incomes, and free energy efficiency devices for low-income, senior and disabled customers. Here's more information:

Telephone service for low-income customers (Universal Lifeline Telephone Service or ULTS)
http://www.cpuc.ca.gov/static/consumers/programs/ults+june+2004.doc

Electric and Gas service for low-income customers (California Alternative Rates for Energy or CARE) and free energy devices (Low-Income Energy Efficiency or LIEE) http://www.cpuc.ca.gov/static/consumers/programs/low-income+energy+services+june+2004.doc

Water service for low-income customers (California Alternative Rates for Water or CARW)
http://www.cpuc.ca.gov/static/consumers/programs/low+income+water+rates+advisory+june+2004.doc

Electric service discounts for large families with low-middle incomes (Family Electric Rate Assistance or FERA); a new service that just started this month.
http://www.cpuc.ca.gov/static/consumers/programs/fera+july+2004.doc

ATTACHMENT I. OVERVIEW OF PG&E GRC PHASE 2 PROPOSALS

Residential

PG&E proposes the following:
- A phase-in new residential baseline quantities;
- Adjust distribution, PPP and generation rates;
- Close Schedules E-7 and EA-7 (residential time of use) to new enrollment and open a single new residential TOU schedule, Schedule E-6.

Here's PG&E's proposed new baseline quantities by territory. Residential rates will rise by about 12%. Higher consumption users rates will rise more than that.

RESIDENTIAL TARGET BASELINE QUANTITIES BASED ON 2000-2003 USAGE

SCHEDULE	E-1, E-6, E-7, E-9, ES, ESR, ET (and CARE)						EM (and CARE)					
	SUMMER			WINTER			SUMMER			WINTER		
TERRITORY	Current Daily(1)	2000-2003 Target Daily	Pctg. Chg.	Current Daily	2000-2003 Target Daily	Pctg. Chg.	Current Daily (1)	2000-2003 Target Daily	Pctg. Chg.	Current Daily	2000-2003 Target Daily	Pctg. Chg.
ALL-ELECTRIC QUANTITIES (kWh)												
P	19.5	19.7	1.0%	31.1	35.1	12.9%	12.5	12.5	0.0%	19.3	20.6	6.7%
Q	10.4	11.2	7.7%	21.9	23.1	5.5%	7.9	7.9	0.0%	18.0	17.8	-1.1%
R	22.1	22.7	2.7%	29.7	32.6	9.8%	13.8	13.8	0.0%	19.8	19.8	0.0%
S	19.5	19.7	1.0%	31.2	32.3	3.5%	12.5	12.5	0.0%	19.4	19.4	0.0%
T	10.4	11.2	7.7%	19.1	20.2	5.8%	7.9	7.9	0.0%	13.5	13.5	0.0%
V	15.3	15.4	0.7%	24.4	26.4	8.2%	8.8	10.7	21.6%	14.7	17.4	18.4%
W	23.8	26.6	11.8%	29.2	29.2	0.0%	14.1	14.1	0.0%	16.8	16.8	0.0%
X	11.4	12.0	5.3%	21.9	23.1	5.5%	10.0	9.8	-2.0%	18.0	17.8	-1.1%
Y	14.5	14.5	0.0%	31.1	30.9	-0.6%	11.3	11.3	0.0%	19.3	19.3	0.0%
Z	14.0	12.6	-10.0%	31.7	31.5	-0.6%	10.1	10.1	0.0%	25.8	25.8	0.0%
BASIC (2) QUANTITIES (kWh)												
P	15.8	15.9	0.6%	12.9	12.7	-1.6%	7.6	7.6	0.0%	7.1	7.1	0.0%
Q	8.5	8.2	-3.5%	13.0	12.6	-3.1%	5.2	5.2	0.0%	7.7	7.5	-2.6%
R	17.5	17.6	0.6%	12.7	12.1	-4.7%	9.0	9.0	0.0%	6.8	6.8	0.0%
S	15.8	15.9	0.6%	12.8	12.5	-2.3%	7.6	7.6	0.0%	6.3	6.3	0.0%
T	8.5	8.2	-3.5%	10.2	9.8	-3.9%	5.2	5.2	0.0%	6.1	6.0	-1.6%
V	8.7	8.8	1.1%	10.4	10.5	1.0%	5.3	5.5	3.8%	6.3	6.5	3.2%
W	18.7	18.9	1.1%	11.9	11.3	-5.0%	10.0	10.0	0.0%	7.1	7.1	0.0%
X	12.2	11.9	-2.5%	13.0	12.6	-3.1%	6.7	6.6	-1.5%	7.7	7.5	-2.6%
Y	11.3	11.5	1.8%	12.9	12.9	0.0%	5.4	5.5	1.9%	7.1	7.1	0.0%
Z	7.3	7.3	0.0%	11.2	11.1	-0.9%	5.8	5.9	1.7%	8.8	8.8	0.0%
SCHEDULE	G-1, G-S, G-T (and CARE)						GM (and CARE)					
GAS QUANTITY (THERMS)												
P	0.5	0.5	0.0%	2.3	2.2	-4.3%	0.4	0.3	-25.0%	1.1	0.7	-36.4%
Q	0.7	0.7	0.0%	2.2	2.0	-9.1%	0.6	0.5	-16.7%	0.9	0.7	-22.2%
R	0.5	0.4	-20.0%	2.0	1.8	-10.0%	0.6	0.4	-33.3%	2.1	1.3	-38.1%
S	0.5	0.5	0.0%	2.1	1.9	-9.5%	0.4	0.3	-25.0%	0.8	0.6	-25.0%
T	0.7	0.7	0.0%	2.0	1.8	-10.0%	0.6	0.5	-16.7%	1.3	1.0	-23.1%
V	0.7	0.7	0.0%	1.9	1.7	-10.5%	0.6	0.5	-16.7%	1.4	1.2	-14.3%
W	0.5	0.5	0.0%	1.9	1.7	-10.5%	0.3	0.3	0.0%	1.1	0.8	-27.3%
X	0.6	0.6	0.0%	2.2	2.0	-9.1%	0.4	0.4	0.0%	0.9	0.7	-22.2%
Y	0.9	0.8	-11.1%	2.7	2.5	-7.4%	0.4	0.5	25.0%	1.1	0.9	-18.2%

(1) Includes baseline quantities effective November 1, 2004.

(2) Basic electric customers represent 81% of total residential electric usage. Individually metered customers represent 99%.

Agricultural

There are big changes proposed for the agricultural sector. PG&E proposes to:
- Establish two new agricultural rate options for all PG&E agricultural customers: (1) non TOU Schedule AG N, and (2) TOU Schedule AG T in place of the six current agricultural rate schedules
- Discontinue ratcheted demand charges. Retain connected load and regular non ratcheted demand charges.
- Modify the unbundled distribution, PPP, and generation components of demand and energy charges. PG&E seeks to increase monthly customer and demand charges, and to establish partial movement toward cost-based targets for customer and demand charges.
- Develop voltage differentials or rates based solely on each customer group's cost of service.
- Eliminate the current unconventional aspects of AG C rate design, which has a ratcheted maximum demand charge in the off peak period only, and lacks a primary or transmission voltage discount. Replaced these with standard maximum and TOU demand charges, and cost based voltage discounts.
- Eliminate the current TOU Installation Charge, TOU Processing Charge, and lower ongoing daily TOU Meter Charge to simplify customer billing, customer understanding, and TOU migration. Retain only the higher ongoing daily TOU meter charge at updated levels.
- Discontinue the current Diesel Alternative Power (DAP) option and the Natural Gas Alternative Power (GAP) option. PG&E recognizes that other parties will propose replacements for these tariffs.
- Eliminate the demand charge rate limiter and the drought relief option.
- Revise the agricultural applicability statement to establish greater consistency between the agricultural class definitions for PG&E and Southern California Edison (SCE). PG&E proposes to revise its agricultural applicability statement to return to an "on the farm" definition where 70 percent or more of electrical usage is for general agricultural end uses. This is to avoid continued protracted piecemeal litigation by commercial food processors seeking agricultural rates.
- Require all accounts with demands less than 500 kilowatts (kW) that meet the new agricultural definition to take service on agricultural rates. Customers with demands over 500 kW for three consecutive months in the most recent 12 months would be required to take service on a commercial or industrial TOU rate, regardless of whether they meet the new agricultural definition. These provisions will apply only to new agricultural accounts or ownership changes in current accounts. All existing agricultural accounts would be grand fathered into the two new agricultural schedules until such time as an ownership change occurs.

In general, ag rates will increase about 2% under the PG&E proposal.

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND PROPOSED AGRICULTURAL ELECTRIC RATES

Line No.	Current PG&E	Average 2003 Number of Accounts	Description	Proposed PG&E
1	AG-1A	34,169	Small non-TOU	AG-NA
2	AG-1B	8,058	Large non-TOU	AG-NB
3	AG-4A	10,425	Medium 2-period TOU < 35 hp	AG-TA
4	AG-4B	7,378	Medium 2-period TOU > 35 hp	AG-TB
5	AG-4C	1,720	Medium 3-period TOU > 35 hp	AG-TC
6	AG-5A	2,823	Large 2-period TOU < 35 hp	AG-TA
7	AG-5B	9,843	Large 2-period TOU > 35 hp	AG-TB
8	AG-5C	817	Large 3-period TOU > 35 hp	AG-TC
9	AG-RA	2,539	Large split-week 2-period TOU < 35 hp	AG-TA
10	AG-RB	822	Large split-week 2-period TOU > 35 hp	AG-TB
11	AG-VA	2,252	Large short-peak 2-period TOU < 35 hp	AG-TA
12	AG-VB	497	Large short-peak 2-period TOU > 35 hp	AG-TB
13	AG-7A	7	Medium 2-period tiered TOU < 35 hp	AG-TA
14	AG-7B	28	Medium 2-period tiered TOU > 35 hp	AG-TB
15	Total	81,378		

<u>Commercial/Industrial (called by PG&E Light and Power (L&P))</u>

In general, commercial/industrial rates are project to decrease. However, that depends upon the customer profile. PG&E proposes to:
- Maintain the current eligibility criteria for each rate schedule, to preserve the current level of customer choice and maintain consistency in metering requirements. The small L&P class will continue to consist of non-demand-metered accounts with maximum demands below 500 kilowatts (kW). Medium L&P will continue to consist of demand-metered accounts with maximum demands below 1,000 kW. Large L&P will continue to consist of all accounts with maximum demands over 1,000 kW.
- Maintain mandatory Time-of-Use (TOU) service for medium L&P accounts with maximum demands over 500 kW, and all large L&P accounts with maximum demands over 1,000 kW. Maintain voluntary TOU for small and medium L&P accounts below 500 kW.
- Require new (post June 18, 2004) accounts that would have met PG&E's prior agricultural class definition, but that do not meet PG&E's new proposed agricultural class definition, to take service on L&P commercial or industrial rates. Limit migration by grand fathering onto agricultural rates the existing agricultural accounts that do not meet the new agricultural definition.
- Establish revenue neutral TOU and non-TOU rates, so that TOU customers benefit only if they have superior load profiles.
- Eliminate the current TOU Installation Charge, TOU Processing Charge, and lower ongoing daily TOU Meter Charge. Retain the higher ongoing daily TOU meter charge.

- Modify the unbundled distribution and generation components of L&P demand and energy charges, as well as total rates.
- Set all L&P distribution and generation rate components to better reflect costs, but mitigate this where necessary to limit bill impacts.
- Set the Schedule A-15 facility charge at $25 per month, the target level adopted by the California Public Utilities Commission (CPUC or Commission) in Decision 97-12-044.
- Eliminate the Schedule E-19 and E-20 summer season peak period and average rate limiters to simplify billing and require customers to pay full cost-based rates.
- Retain power factor adjustments for large L&P accounts and medium L&P accounts with maximum demands over 500 kW, and express them as a rate per kilowatt-hour (kWh) rather than as a percent of billed revenue, to eliminate the need to establish the charge based on a calculation of bundled charges.
- Establish traditional cost-based voltage discounts in the medium and large L&P classes on distribution and generation components.
- Eliminate the current nonfirm program and transfer customers to Base Interruptible Program Schedule E-BIP.
- Eliminate water agency Schedule E-25, and small oil pumping Schedule E-36, to simplify tariffs.
- Eliminate the current Optimal Billing Period program applicable to qualifying seasonal medium and large L&P mandatory TOU customers with maximum demands over 500 kW, such as food processors and other customers.
- Make adjustments to Schedules E-19 and E-20 to account for PG&E's proposed switch from 30-minute to 15-minute demand intervals.

TABLE 4-1
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT LIGHT AND POWER ELECTRIC RATES

Line No.	Current PG&E	Average 2003 Number of Accounts	Description
1	**Small L&P**		
2	A-1	359,302	Small non-demand non-TOU
3	A-6	26,878	Small non-demand TOU
4	A-15	735	Direct current service
5	E-36	96	Small non-demand non-TOU oil pumping
6	**Medium L&P**		
7	A-10	54,549	Medium demand non-TOU
8	E-19 Voluntary	7,791	Medium voluntary demand TOU
9	E-19 Mandatory	2,615	Medium mandatory demand TOU
10	E-25	4	Medium water agency TOU short-peak
11	E-37	490	Medium demand TOU oil pumping
12	**Large L&P**		
13	E-20	1,124	Large mandatory demand TOU
14	Total	453,584	