

**BEFORE THE PUBLIC UTILITIES COMMISSION  
OF THE STATE OF CALIFORNIA**

Application of Pacific Gas and Electric  
Company for Authority to Increase Revenue  
Requirements to Recover the Costs to Deploy  
an Advanced Metering Infrastructure

(U 39 E)

A.05-06-028  
(Filed June 16, 2005)

**ELEVENTH SEMI-ANNUAL ASSESSMENT REPORT ON  
THE DEPLOYMENT OF PACIFIC GAS AND ELECTRIC  
COMPANY'S (U 39 E) ADVANCED METERING  
INFRASTRUCTURE PROGRAM AND ELEVENTH  
QUARTERLY REPORT ON THE IMPLEMENTATION  
PROGRESS OF THE SMARTMETER™ PROGRAM  
UPGRADE**

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March 30, 2012

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Pacific Gas and Electric Company (PG&E) submits the attached Eleventh Semi-Annual Assessment Report on the deployment of its Advanced Metering Infrastructure (AMI) Program and the Eleventh Quarterly Report on the implementation progress of its SmartMeter™ Program Upgrade. PG&E combines both the semi-annual and quarterly reports from the AMI and SmartMeter™ proceedings into a single filing as a result of consultations with the Energy Division. These reports comply with the requirements of D.06-07-027, Ordering Paragraph (O.P.) 16, D.09-03-026, O.P. 7, and the May 4, 2010 Assigned Commissioner's Ruling in A.05-06-028.

Respectfully submitted,

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Pacific Gas and Electric Company  
Advanced Metering Infrastructure Semi-Annual Assessment Report  
SmartMeter™ Program Quarterly Report  
March 2012

(CPUC Decisions 06-07-027 and 09-03-026)

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March 30, 2012

1 **Pacific Gas and Electric Company**  
2 **Advanced Metering Infrastructure Semi-Annual Assessment Report**  
3 **SmartMeter™ Program Quarterly Report**  
4 **March 2012**

5 **I. Executive Summary**

6 This is Pacific Gas and Electric Company's (PG&E or the Company) eleventh semi-  
7 annual assessment report (Report) regarding the deployment of PG&E's Advanced  
8 Metering Infrastructure (AMI) Program (now the SmartMeter™<sup>1</sup> Program) and serves as  
9 the eleventh quarterly report for the SmartMeter™ Program Upgrade.<sup>2</sup>

10 Consistent with the AMI Decision, this Report provides updates in the following  
11 areas: (1) advances in AMI technology; (2) a self-assessment of AMI system operating  
12 performance based on performance criteria that PG&E established with input from the  
13 Commission's Energy Division and the Division of Ratepayer Advocates (DRA); (3) an  
14 updated cost-effectiveness review; and (4) the ability to provide real-time usage data  
15 and customers' interest in such data.<sup>3</sup>

16 **A. Introduction**

17 PG&E's SmartMeter™ Program is the largest installation of advanced meters in  
18 North America, with nearly nine million electric and gas SmartMeters™ installed as of  
19 the end of 2011. Specifically, PG&E installed 370,500 first-generation SmartMeters™  
20 between March 2006 and December 2008, and as of the end of 2011 had installed

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<sup>1</sup> SmartMeter™ is a licensed trademark of SmartSynch, Inc.

<sup>2</sup> PG&E proposed its SmartMeter™ Program in Application (A.) 05-06-028, which the California Public Utilities Commission (CPUC or Commission) approved in Decision (D.) 06-07-027 (the AMI Decision). The AMI Decision requires that PG&E provide the Commission with a semi-annual report assessing the SmartMeter™ deployment. See Ordering Paragraph (O.P.) 16. PG&E issued an updated SmartMeter™-proposal (the SmartMeter Upgrade) in A. 05-06-028, which the Commission approved in D.09-03-026 (the Upgrade Decision). There, the Commission directed PG&E to provide quarterly reports on the Program. See O.P. 7. PG&E conferred with the Commission's Energy Division to establish the information to be provided and has prepared this Report to comply with the requirements of both the AMI Decision (O.P. 16) and the Upgrade Decision (O.P. 7).

<sup>3</sup> D.06-07-027 at pp. 57-58.

1 4,730,594 electric and 4,159,060 gas second-generation SmartMeters™, with 835,711  
2 meters potentially remaining to exchange.

3 Indeed, PG&E is a pioneer in the SmartMeter™-space, paving the way for utilities  
4 across the country to similarly develop the critical infrastructure necessary to realize the  
5 customer benefits that will follow from the development of a Smart Grid.

6 Playing a foundational role in modernizing the electric grid, SmartMeters™ in  
7 California are a critical part of statewide policy to better manage energy, and to create  
8 the smarter grid we need to incorporate more renewable resources, deliver cleaner  
9 energy to our customers and realize the State's ambitious energy efficiency goals.

10 More recently, PG&E has pioneered an "opt-out" alternative<sup>4</sup> for customers who do  
11 not wish to have SmartMeters™ – a previously-unanticipated practice that utilities  
12 across the country (e.g., Central Maine Power, Portland General Electric, NV Energy)  
13 have emulated; and PG&E also has launched the Green Button, a means for customers  
14 to download their energy-usage data in a standard format.

15 While the majority of PG&E's customers have received SmartMeters™ and not  
16 registered any concern, a relatively small number of PG&E customers continued to  
17 protest SmartMeters™ during the second-half of 2011, principally due to concerns  
18 regarding Radio Frequency (RF).<sup>5</sup> Some residential customers formally requested that  
19 PG&E add them to the Delay List that PG&E initiated in April 2011; PG&E established  
20 an Extended Delay List that represents other delayed customer populations, including  
21 those who: (1) affirmatively refused PG&E's attempt to install a SmartMeter™;

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<sup>4</sup> See A.11-03-014.

<sup>5</sup> These customers maintained their concerns notwithstanding PG&E's substantial outreach regarding the Federal Communications Commission's (FCC) finding that PG&E's technology satisfies the FCC's standards, and the California Council on Science and Technology's (CCST) determination that PG&E's technology satisfied every known RF-health-standard by a wide margin. Each of these documents is posted on PG&E's website at [www.pge.com/rf](http://www.pge.com/rf).

1 (2) notified PG&E that they intended to remove their SmartMeter™ upon installation; (3)  
2 failed to provide PG&E with access to their residences (e.g., locked gate, unleashed  
3 dog) to allow PG&E to install a SmartMeter™ despite multiple PG&E-attempts to do so;  
4 (4) called PG&E to request that the existing SmartMeter™ be removed; or (5) removed  
5 their SmartMeter™ on their own.

6 Consistent with Decision 12-02-014, which approved PG&E's SmartMeter™ Opt-Out  
7 Program, PG&E sent certified letters to each of these roughly 175,000 customers to  
8 inform them of the Program. The letter attempts to facilitate the customers' election to  
9 receive SmartMeters™ or opt-out, and set a May 1, 2012 deadline for responses to  
10 enable the substantial completion of both the Company's remaining SmartMeter™  
11 deployment and its SmartMeter™ Opt-Out exchanges by the end of 2012. Depending  
12 on the opt-out preferences of customers in the coming months, PG&E anticipates  
13 upgrading a small number of meters in 2013.

14 As of the time of this filing, 14,904 customers have asked to opt-out of the  
15 SmartMeter™ Program, and 6,730 have requested SmartMeters™.

16 B. Update on the SmartMeter™ Program

17 PG&E's SmartMeter™ Program is nearing the completion of its objectives, as the  
18 Commission outlined in the AMI and Upgrade Decisions. As of the end of 2011, PG&E  
19 had installed nearly nine million second-generation gas and electric SmartMeters™ –  
20 far and away the largest AMI-deployment in North America – and the associated  
21 network equipment and information technology (IT) necessary to operate PG&E's  
22 SmartMeter™ system.

1 This section of the Report provides an overview of Program developments and  
2 PG&E's progress on individual elements of the Program during the last six months of  
3 2011.

4 1. Progress in PG&E's AMI Deployment

5 PG&E continues to deploy solid-state electric meters communicating over a radio  
6 frequency (RF) mesh network, and gas modules communicating over an RF network.  
7 The deployment of the RF Mesh network was planned to consist of an initial phase to  
8 deploy Access Points (APs) at defined locations throughout PG&E's service territory,  
9 followed by subsequent phases to deploy additional APs to strengthen the network  
10 where required. As of December 31, 2011, PG&E had installed all of the 11,379 electric  
11 network devices (APs and Relays) and 4,817 gas network data collection units (DCUs)  
12 that it planned to install.<sup>6</sup>

13 As of December 31, 2011, approximately 8,858,000 meters (approximately  
14 4,711,000 electric and 4,147,000 gas) have been converted to, or replaced with,  
15 SmartMeter™ technology, representing approximately 91 percent of the total PG&E  
16 meter population. Of this number, PG&E has “activated” approximately 5,042,000  
17 meters and recorded \$128.7 million of benefits to the gas and electric SmartMeter™  
18 balancing accounts. Further details of the SmartMeter™ Program's deployment status  
19 are provided in Section II of the Report. Further details of the SmartMeter™ Program's  
20 cost and benefit status are detailed in Section III of this Report.

21 During the second half of 2011, PG&E continued to expand and enhance customer  
22 outreach activities to address customers' concerns about SmartMeter™ technology.

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<sup>6</sup> Note that although all network equipment is deployed, there may be unique, individual locations requiring modifications to optimize performance. Customers' delay in accepting their SMs, as represented in the Extended Delay List, already has reduced connectivity (i.e., degraded the RF-network) in some cases. In addition, opt-outs from the SmartMeter™ Program approved by D.12-02-014 will degrade the RF-network and its performance, and will therefore require reinforcement.



1 These activities included increased customer contacts before, during, and after  
2 deployment through direct mail, mass media, online content, and community-outreach  
3 events. In addition, PG&E has continued to ensure the accuracy of its SmartMeters™  
4 through meter-testing at the manufacturers' factories, random-sample testing at PG&E's  
5 Fremont Meter Shop, and field-testing at customer premises. PG&E will field-test any  
6 SmartMeter™ device upon customer request.

7 2. Program Costs and Benefits

8 In late 2010 and early 2011, the SmartMeter™ Project Management Office (PMO)  
9 performed a detailed review of all workstream forecasts. The Program sought and  
10 received approval in February 2011 from PG&E's Board of Directors to incur an  
11 additional \$129 million in costs (to be borne by Company shareholders) to complete the  
12 scope of the project. As a result, the Program is now expected to exceed the CPUC-  
13 authorized cost cap of \$2,206 million. As reported in its financial disclosures, PG&E  
14 recorded an earnings reserve of \$36 million, representing the current forecast of capital-  
15 related costs by which the Company expects to exceed the CPUC-authorized cost cap.  
16 PG&E will continue to update its forecasts as the Program continues and may incur  
17 additional costs.

18 As of December 31, 2011, PG&E had allocated the entire \$2,335 million Board-  
19 authorized project amount to Program workstreams, and the PMO continues to monitor  
20 actual spending against the Board-approved forecast, as well as monitor issues and  
21 risks that could contribute to potential cost overruns. SmartMeter™ Program  
22 expenditures through December 31, 2011 totaled approximately \$2,219 million of the  
23 \$2,335 million.

1        3. System Performance Criteria

2        System performance metrics are provided in Table IV-2.

3        4. Customer Interest in Accessing Real-Time Usage and Pricing Information

4        PG&E launched its SmartRate™ Program in May 2008. During the 2011 season,  
5 PG&E called 15 SmartDay™ events. As of December 31, 2011, the SmartRate™  
6 Program had approximately 22,000 active residential customers. Details of the  
7 SmartRate™ Program are provided in Section V of this Report.

8        5. SmartMeter™ Information Technology Progress

9        During the last half of 2011, PG&E substantially completed the implementation of the  
10 complex IT systems and interfaces necessary to support the SmartMeter™ Program.  
11 Highlights of PG&E's IT development over the last two quarters of 2011 are provided in  
12 Section VI of this Report.

13       6. Advances in AMI Technology

14       PG&E continues to monitor metering and network collector technologies as the AMI-  
15 industry advances. In addition, PG&E continues to identify and approve engineering  
16 solutions using specific technologies and products that enable PG&E to deploy  
17 SmartMeters™ in difficult-to-reach meter locations such as urban areas and remote  
18 locations. These solutions may require existing network communication technologies or  
19 other technologies not yet available, as conditions dictate.

20       PG&E continues to participate in industry activities related to advanced metering and  
21 communication networks, as well as monitor announcements and activities that are  
22 significant in the industry, as reported in Section VII of this Report. These activities  
23 allow PG&E to stay actively involved in and aware of industry developments.

1        7. SmartMeter™ Transition to Operations

2        Beginning in 2011, the SmartMeter™ Program began to transition activities that are  
3 of a recurring nature (i.e., activities that will continue after the Program has been  
4 completed) to PG&E's traditional operations organizations. PG&E initiated significant  
5 employee outreach and change management activities to support the transition. This  
6 transition planning and implementation is now substantially complete, as described in  
7 Section VIII of this Report.

8        **II. Progress in PG&E's AMI Deployment**

9        A. Overview

10        In 2011, PG&E substantially completed its deployment of necessary network-  
11 infrastructure and its development of necessary IT to support the SmartMeter™  
12 Program. Concurrently, PG&E continued to deploy SmartMeter™-endpoints, installing  
13 approximately 881,267 and 502,103 gas and electric SmartMeters™, respectively, in  
14 2011, in addition to retrofitting 126,264 first generation electric meters.

15        As of the beginning of 2012, the SmartMeter™ Program has 835,711 remaining  
16 meters to exchange. Subject to various outstanding issues, including customers'  
17 elections to opt-out of the SmartMeter™ Program pursuant to Decision 12-02-014, the  
18 Program's 2012-activities will focus on substantially completing the remaining meter  
19 deployment. The deployment schedule is dependent upon the availability of trained  
20 resources, an effective supply chain, and access to customer premises to make the  
21 necessary changes at each service location. Deployment planning adjustments may be  
22 required due to several factors – including customer considerations, supply chain  
23 constraints, and labor availability – which could affect the scheduling of meter endpoint  
24 installations, including beyond 2012. These undertakings are further complicated by the

1 competing urgency to remove the SmartMeters™ of customers who opt-out of the  
2 SmartMeter™ Program, which PG&E has prioritized since the SmartMeter™ Opt-Out  
3 Program's February 2012 inception.

4 PG&E launched its SmartMeter™ Opt-Out Program on February 1, 2012,  
5 immediately following the CPUC's issuance of Decision 12-02-014. The SmartMeter™  
6 Opt-Out Program provides residential customers with the option to have analog electric  
7 and gas meters. Customers electing analog meters will pay an initial charge and an  
8 ongoing monthly fee. The fees were set on an interim basis at \$75 up-front and \$10  
9 monthly for non-CARE/FERA customers, and \$10 upfront and \$5 monthly for  
10 CARE/FERA customers.

11 The CPUC's decision also ordered a second phase of the proceeding to consider  
12 cost recovery, including adopting final amounts for the customer fees above, and a  
13 community-based opt-out. Phase 2 of the proceeding is expected to begin in mid-2012.

#### 14 B. Infrastructure Installations

15 As of December 31, 2011, PG&E had installed approximately 9.2 million meters  
16 (including retrofits) with SmartMeter™ technology. As noted above, the Upgrade  
17 Decision approved PG&E's plan to replace all electric meters that do not possess  
18 Upgrade technology, and PG&E has deployed 364,097 retrofit endpoints to replace  
19 those endpoints relying on the Company's first-generation technology, PowerLine  
20 Carrier. PG&E's progress as of December 31, 2011 is summarized in Table II-1.

1 **Table II - 1**

**AMI Project Status as of December 31, 2011**

<b>Progress Toward Completion</b>	<b>Total Budgeted Plan</b>	<b>Actual</b>	<b>% of Total Project Plan Installed</b>
Electric Network - RF Network	1,553	1,371	88%
Gas Network Collectors	5,000	4,815	96%
Electric Network Enabled Locations	5,260,391	5,260,391	100%
Electric Meter Installations*	5,630,886	5,074,494	90%
Electric Meters Activated	5,260,391	2,503,631	48%
Gas Network Enabled Locations	4,449,040	4,449,040	100%
Gas Meter-Module Installations	4,449,040	4,147,136	93%
Gas Meter-Modules Activated	4,449,040	2,538,535	57%

\*Includes installation of retrofitted SmartMeters™.

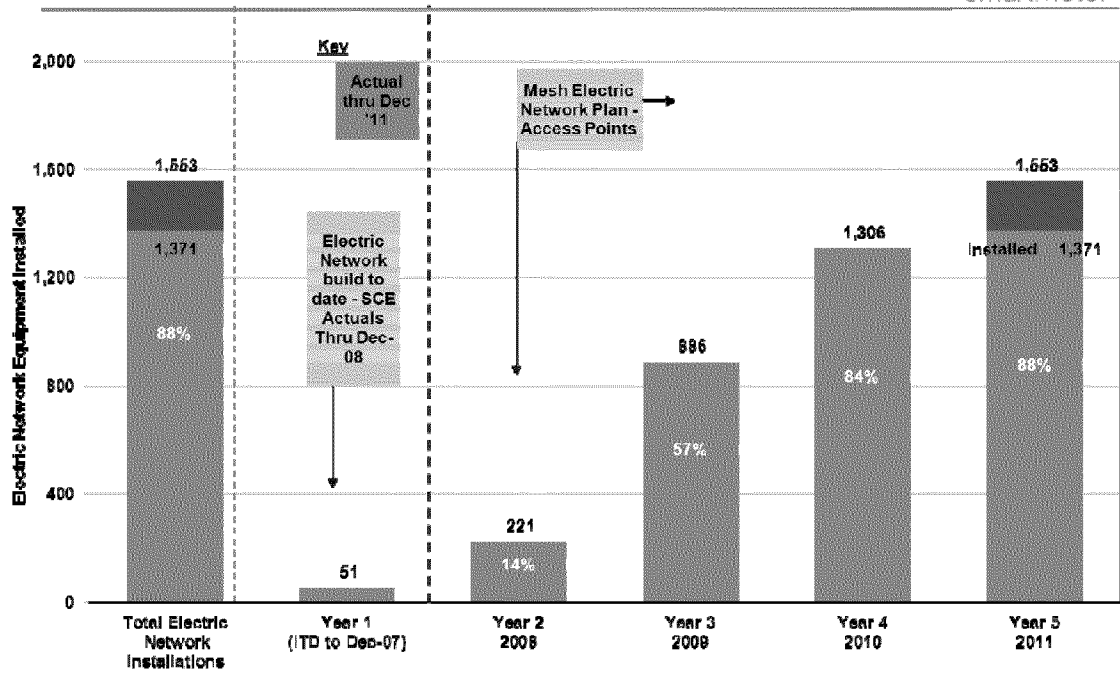
Note: Meter growth occurring in 2011 and 2012 was funded in the 2011 GRC Decision and is not included in the above table.

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PG&E has completed the deployment of the gas and electric network infrastructure and continues to make progress with the installation and activation of its electric SmartMeters™ and smart gas modules. The following figures summarize the progress of PG&E's SmartMeter™ Program implementation in each respective area through December 31, 2011. The percent-of-plan refers to the total (five-year) Program completion and provides perspective on PG&E's installation progress. PG&E reports actual and projected deployments and installations on a calendar year (CY) basis.

1 **Table II – 2**

Cumulative Electric Network Installations: Substation Communication Equipment (SCE) & RF Mesh Access Points



2

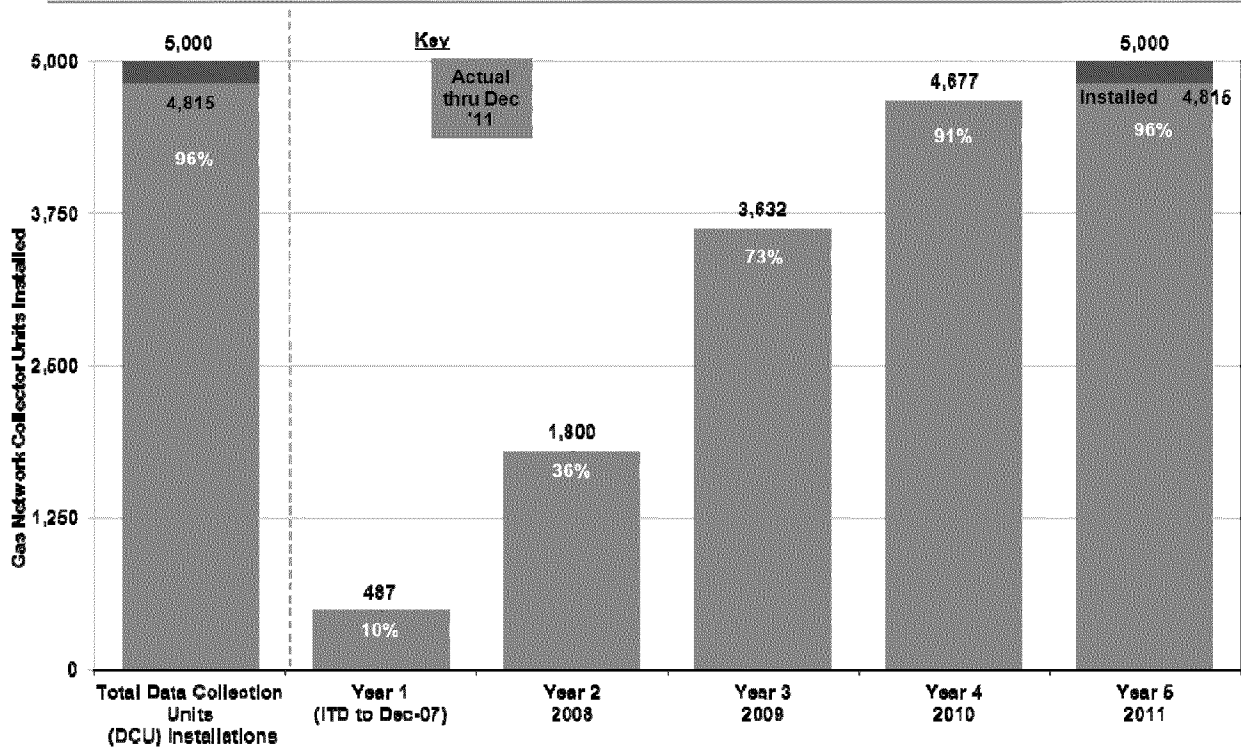
Electric Network - Substation SCE		Total	Yr 1 (to Dec-07)				
Cumulative Installed thru 12/11		51	51				
Plan		51	51				
Electric Network - RF Mesh Access Points		Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Cumulative Installed thru 12/11		1,371	-	221	886	1,306	1,371
Plan		1,553	-	221	886	1,306	1,553

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4

1 **Table II - 3**

Cumulative DCU Network Installations



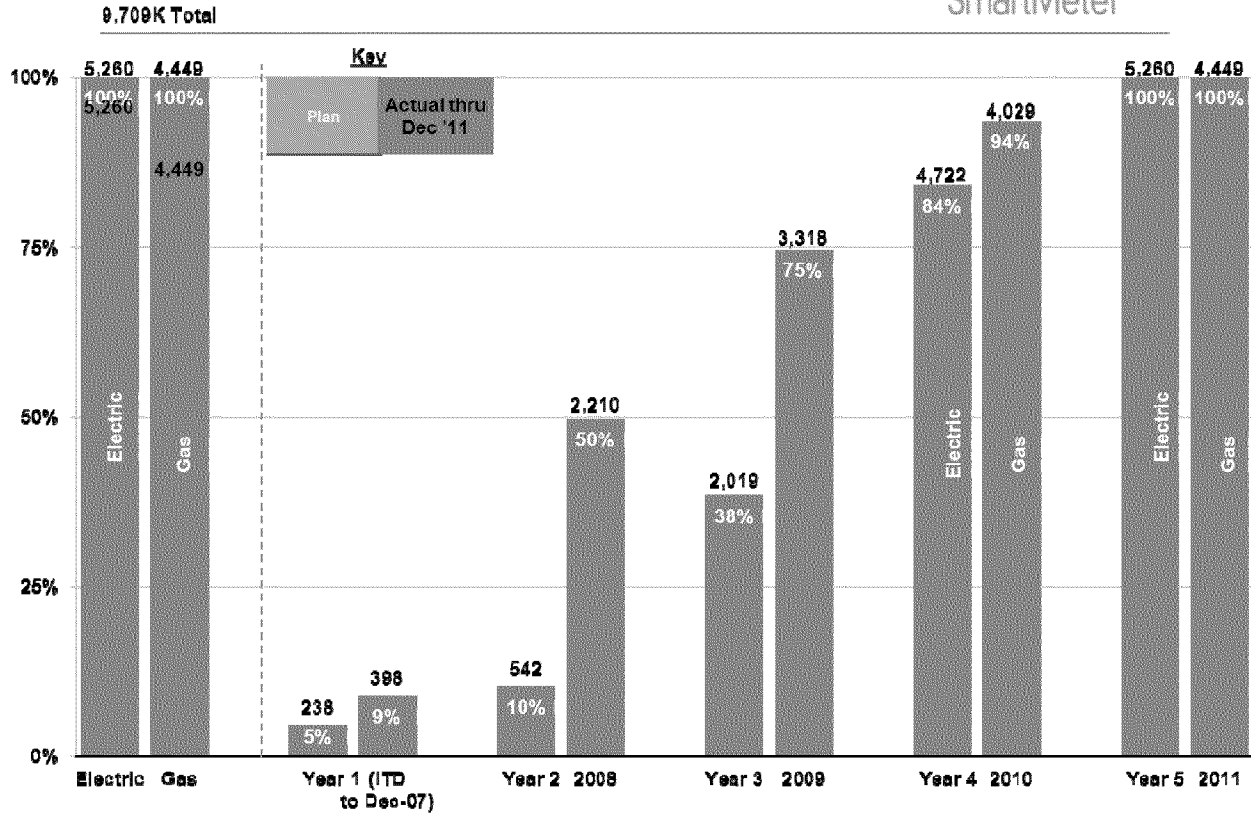
2

Cumulative Data Collection Unit (DCU) Installations	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Installed thru 12/11	4,815	487	1,800	3,632	4,677	4,815
Plan	5,000	487	1,800	3,632	4,553	5,000

3

1 **Table II - 4**

Cumulative Network Enabled Locations (in 000s)



2

Cumulative Network Enabled Locations (000)	Total	2007		2008		2009		2010		2011	
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Enabled thru 12/11	9,709K	238K	398K	542K	2,210K	2,019K	3,318K	4,424K	4,162K	5,260K	4,449K
Plan*	9,709K	238K	398K	542K	2,210K	2,019K	3,318K	4,722K	4,029K	5,260K	4,449K

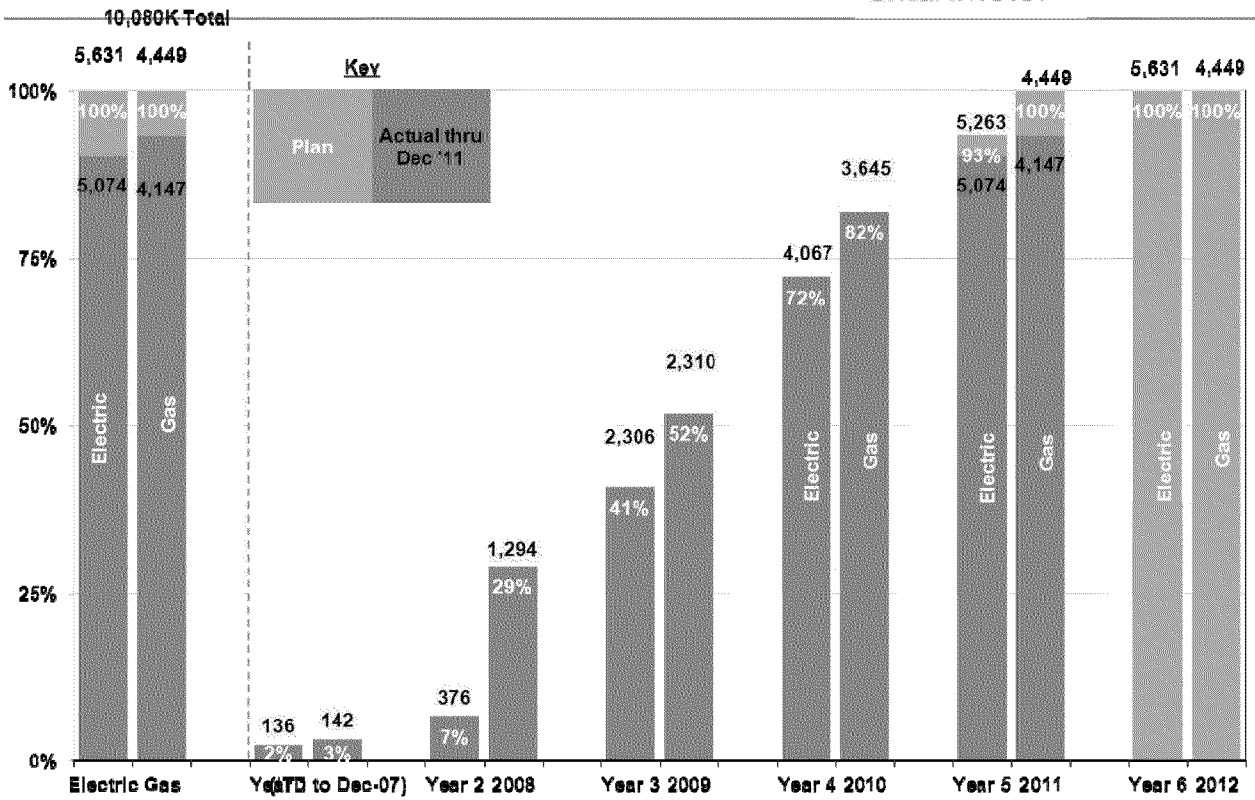
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\* Enabled electric network is presented on an access point basis, with prior periods on a consistent basis.



1 **Table II - 5**

Cumulative Meter-Module Installations (in 000s)



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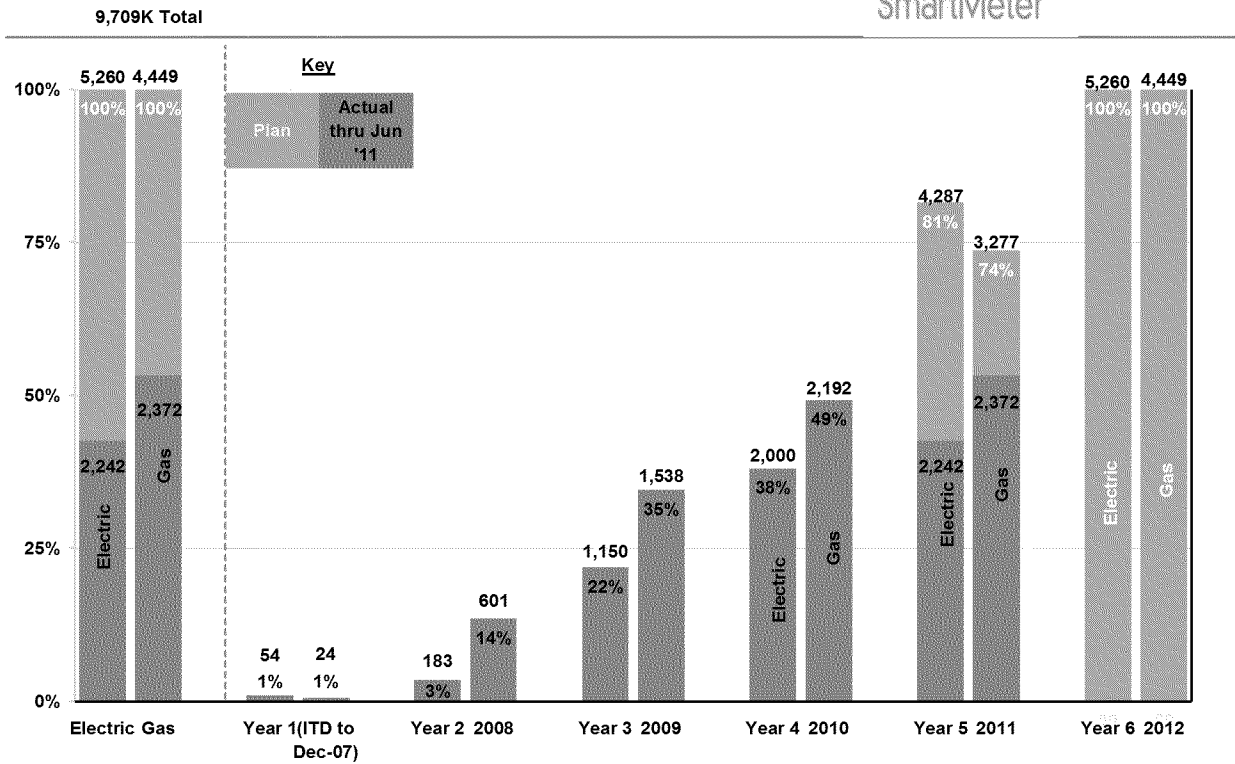
Cumulative Meter-Module Installations (000)	Total	Year 1		Year 2		Year 3		Year 4		Year 5		Year 6	
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Installed thru 12/11	5,074K	136K	142K	376K	1,294K	2,306K	2,310K	4,067K	3,645K	5,074K	-	-	-
Plan*	10,080K	136K	142K	376K	1,294K	2,306K	2,310K	4,067K	3,645K	5,263K	4,449K	5,631K	4,449K

\*Planned total includes installation of retrofitted SmartMeters™ and updated meter growth forecast through 12/31/11.

3

1 **Table II - 6**

Cumulative Meter-Modules Activated (in 000s)



2

Cumulative Meters Activated	Total	2007		2008		2009		2010		2011		2012	
		Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Gas
Activated thru 12/11	5,042K	54K	24K	183K	601K	1,150K	1,538K	2,000K	2,192K	2,504K	2,539K	-	-
Plan*	9,709K	54K	24K	183K	601K	1,150K	1,538K	2,485K	2,247K	4,287K	3,277K	5,260K	4,449K

\* Includes updated meter growth forecast through 12/31/11.

3

1 **III. Program Costs and Benefits**

2 A. SmartMeter™ Program Costs

3 The SmartMeter™ PMO maintains governance over the allocation of both the  
4 annual budget and the budget-to-completion for each of the respective workstreams.  
5 For purposes of this Report, the workstreams are summarized into four major  
6 categories: Field Delivery, Information Technology, Customer & SM (SmartMeter™)  
7 Operations, and PMO.

8 The Program budget includes a risk-based allowance, which the CPUC authorized  
9 to address unanticipated costs necessary to complete the defined Program work scope.  
10 For the SmartMeter™ Program, only the officer-led Steering Committee can approve a  
11 workstream expenditure that requires a draw against the risk-based allowance funding  
12 category. If a draw against the risk-based allowance is approved, the workstream  
13 budget is shown with an increase in approved funds, and the risk-based allowance  
14 category is shown with an equal offsetting amount. In addition, the PMO recommends  
15 other reallocations, both increases and decreases, within and among workstream  
16 budgets, as circumstances require. Table III-1 indicates the approved adjustments to  
17 the workstream budgets, which reflect both the allocation of the \$178 million risk-based  
18 allowance that the CPUC approved and the additional \$129 million in shareholder  
19 funding that PG&E's Board approved in February 2011.

20 Through December 31, 2011, the SmartMeter™ Program incurred costs of  
21 approximately \$2,219 million (\$1,805 million in capital and \$414 million in expense). Of  
22 this total dollar amount, Field Delivery activities have cost approximately \$1,460 million  
23 (66 percent) and IT-related activities have cost approximately \$478 million (22 percent).  
24 The remaining 12 percent is attributed to the Customer & SM Operations and PMO

1 categories. The Program's total estimated cost of \$2,335 million is based on the  
 2 combined CPUC cost authorizations of the AMI Decision (\$1,739 million) and Upgrade  
 3 Decision (\$467 million), as well as the additional \$129 million of Board-approved  
 4 shareholder funding.

5 **Table III – 1**

(\$ Millions)	TOTAL	Field Delivery	Information Technology	Customer & SM Operations	PMO	Risk-Based Allowance
Plan as of June 30, 2011	2,206	1,438	493	179	96	
Cost Adjustments	129	99	-	21	10	
Plan as of December 2011	2,335	1,537	493	200	106	
Risk-Based Allowance Drawdown to Date	178					178
Future Potential Use	-					-
Total Risk-Based Allowance	(178)					-
Additional Board-approved Cost	129					
Actuals Thru December 31, 2011	2,219	1,460	478	180	100	
% of Plan	95%	95%	97%	90%	95%	

6 Note: Totals subject to rounding

7 The Customer & SM Operations category includes \$54.8 million specifically  
 8 authorized in the AMI Decision for the purpose of marketing Critical Peak Pricing  
 9 programs. As of December 31, 2011, PG&E utilized approximately \$37.0 million of this  
 10 \$54.8 million in support of SmartRate™ marketing.

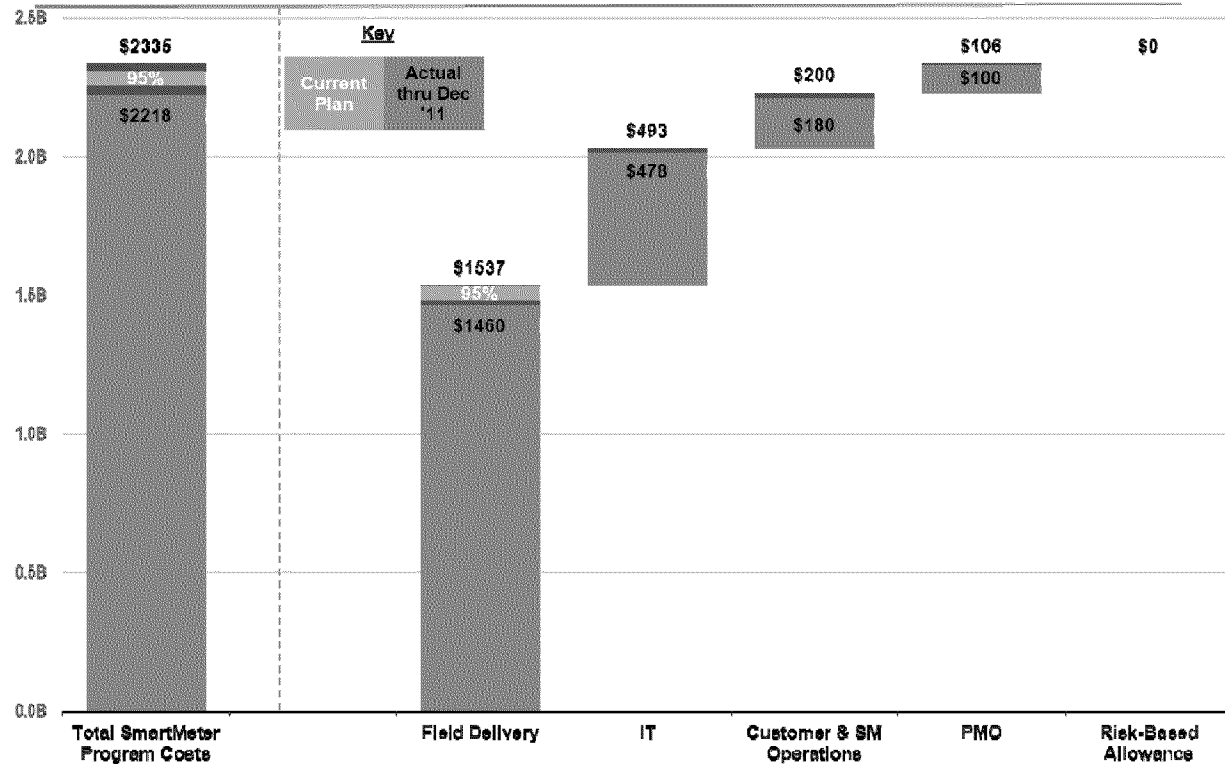
(Thousands of Dollars)	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	Total
SmartRate™ Marketing & Education and Customer Web Presentment	0	349	1,166	6,811	6,828	2,500	19,385	37,038

11  
 12 Tables III-2 through III-7 show PG&E's incurred costs from inception through  
 13 December 31, 2011, for the SmartMeter™ Program, as well as each respective budget  
 14 category. The percent-of-expenditures refers to the total incurred expenditure through  
 15 December 31, 2011 as a percentage of the adjusted workstream budgets at Program  
 16 completion.

17  
 18

1 **Table III – 2**

Total SmartMeter Program Costs (\$ Millions)



2

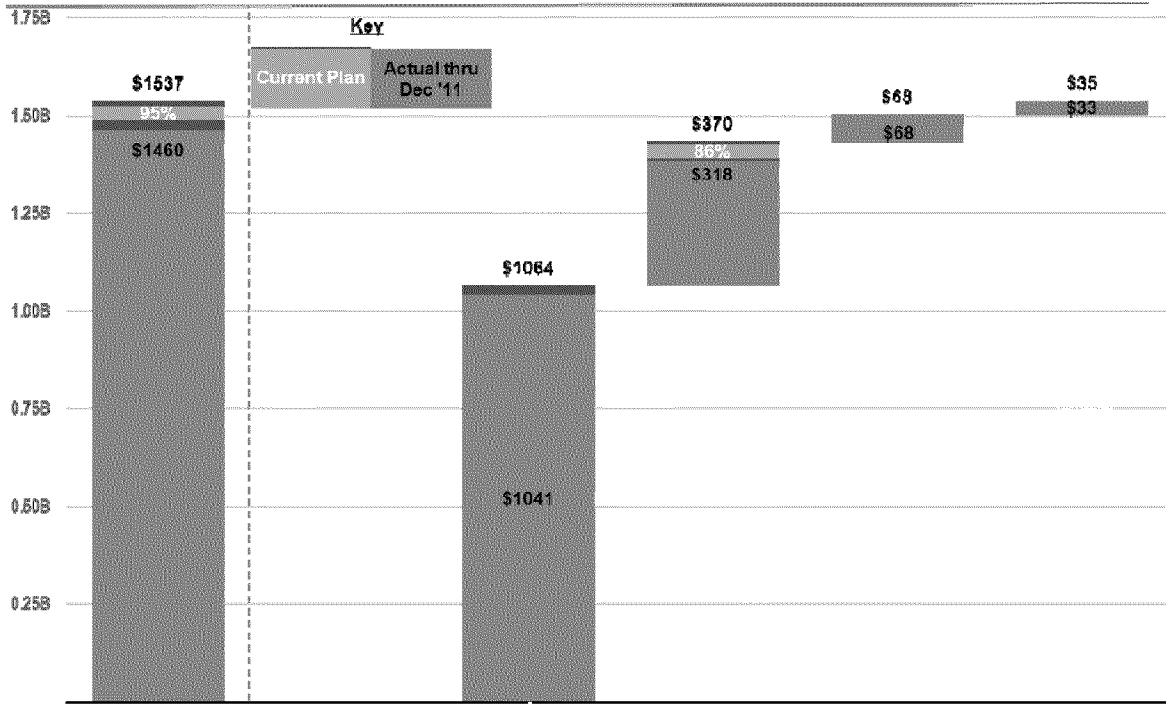
\$ Millions	Total SmartMeter Program Costs	Field Delivery	IT	Customer & SM Operations	PMO	Risk-Based Allowance
Actual thru December 31, 2011	\$ 2,218	1,460	478	180	100	N/A
Plan as of June 30, 2011	\$ 2,335	1,537	493	200	106	
Cost Changes/Reallocation	\$ -	-	-	-	-	-
Plan as of December 31, 2011	\$ 2,335	1,537	493	200	106	
% of Plan completed	95%	95%	97%	90%	95%	

3 Note: Totals subject to rounding

4

1 **Table III- 3**

Field Delivery Costs (\$ Millions)



2

\$ Millions	Total Field Delivery	Strategic Relationships	Endpoint Installation	Field Delivery Office	Network Installation
Actuals thru December 31, 2011	1,460	1,041	318	68	33
Plan as of June 30, 2011	1,537	1,064	370	68	35
Cost Changes/Reallocation	-	-	-	-	-
Plan as of December 31, 2011	1,537	1,064	370	68	35
% of Plan Expended	95%	98%	86%	100%	93%

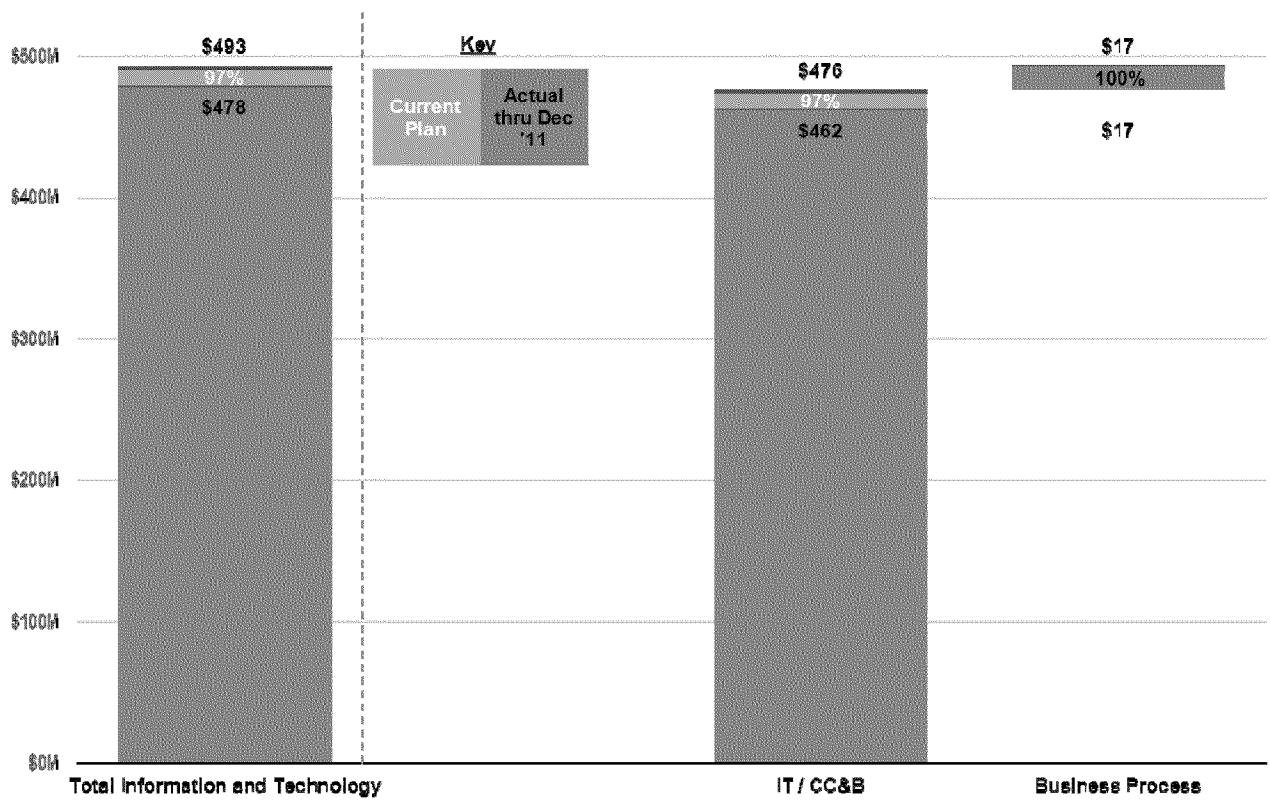
\$ Millions	Network Installation	Electric Network	Gas Network
Actuals thru December 31, 2011	\$ 33	21	12
Plan as of June 30, 2011	\$ 35	24	12
Cost Changes/Reallocation	\$ -	-	-
Plan as of December 31, 2011	\$ 35	24	12
% of Plan Expended	93%	89%	99%

Note: Totals subject to rounding. Some Field Delivery (FD) costs have been reallocated among the FD subcategories to align with the project's management of the FD activities.

3  
4

1 **Table III – 4**

**Information Technology Costs (\$ Millions)**



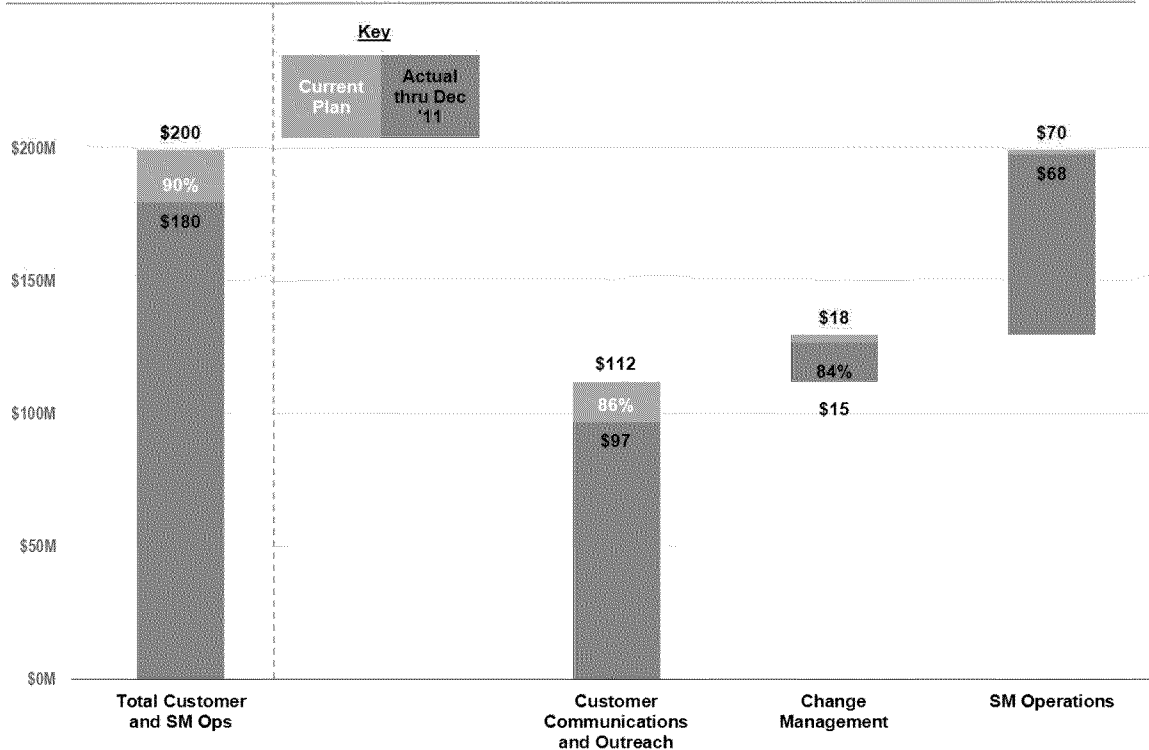
2

\$ Millions	Total Information and Technology	IT / CC&B	Business Process
Actuals thru December 31, 2011	\$ 478	462	17
Plan as of June 30, 2011	\$ 493	476	17
Cost Changes/Reallocation	\$ -	-	-
Plan as of December 31, 2011	\$ 493	476	17
% of Plan Expended	97%	97%	100%

3

1 **Table III - 5**

Customer and SM Operations Costs (\$ Millions)



2  
3

\$ Millions	Total Customer and SM Ops	Customer Communications and Outreach	Change Management	SM Operations
Actuals thru December 31, 2011	\$ 180	97	15	68
Plan as of June 30, 2011	\$ 200	112	18	70
Cost Changes/Reallocation	\$			
Plan as of December 31, 2011	\$ 200	112	18	70
% of Plan Expended	90%	86%	84%	97%

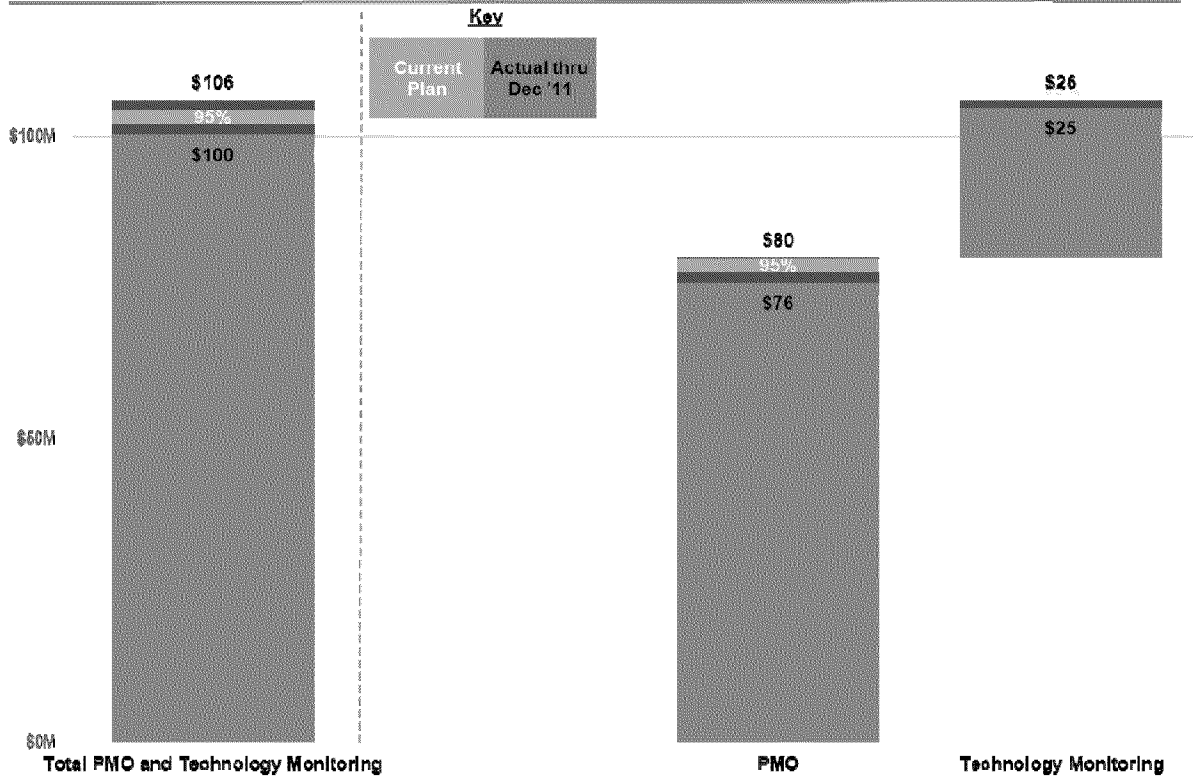
4  
5

Note: Totals subject to rounding



1 **Table III - 6**

PMO & Technology Monitoring Costs (\$ Millions)



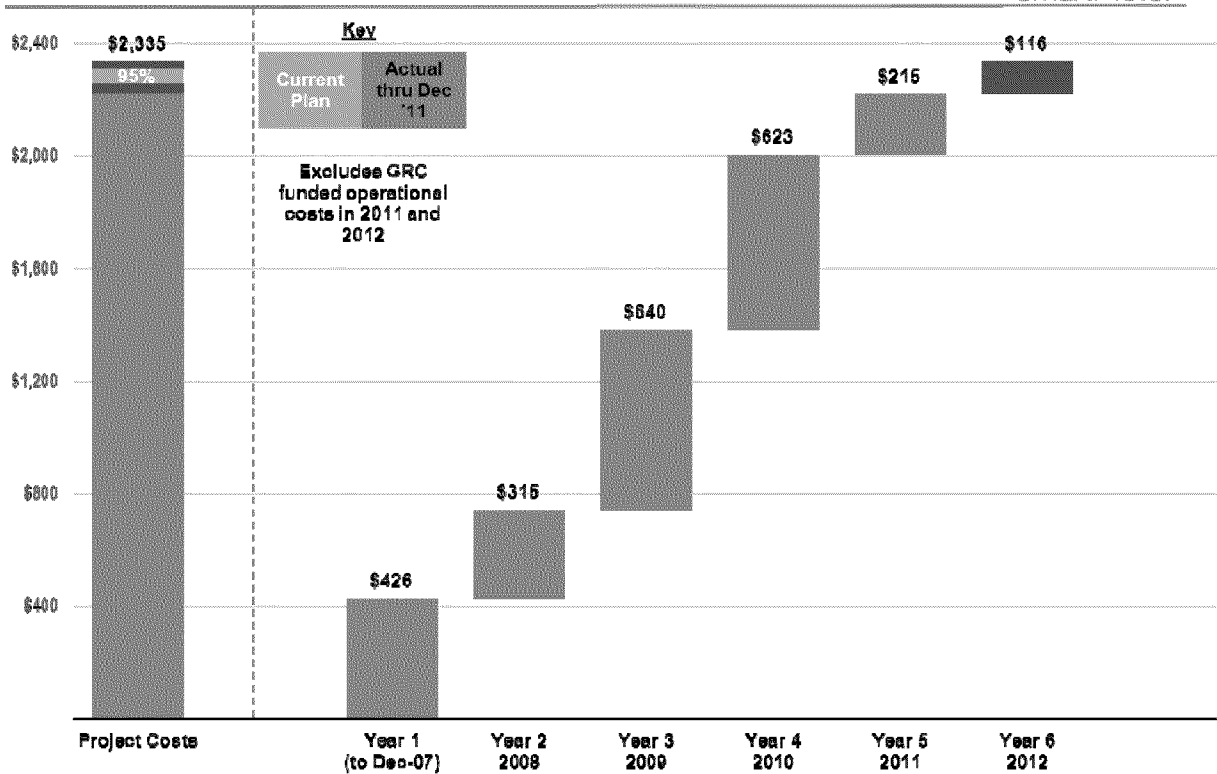
2  
3

\$ Millions	Total PMO and Technology Monitoring	PMO	Technology Monitoring
Actuals thru December 31, 2011	\$ 100	76	25
Plan as of June 30, 2011	\$ 106	80	26
Cost Changes/Reallocation	\$ -	-	-
Plan as of December 31, 2011	\$ 106	80	26
% of Plan Expended	95%	95%	95%

4 Note: Totals subject to rounding

1 **Table III – 7**

**Total Project Costs By Year (\$ Millions)**



2

\$ Millions	Project Costs	Year 1 (to Dec-07)	Year 2 (CY 2008)	Year 3 (CY 2009)	Year 4 (CY 2010)	Year 5 (CY 2011)	Year 6 (CY 2012)
Actuals thru December 31 2011	\$ 2,219	426	315	640	623	215	-
Plan as of December 31, 2011	\$ 2,335	426	315	640	623	215	116
% of Plan Expended	95%	100%	100%	100%	100%	100%	0%

3

Note: Totals subject to rounding

4

1 B. Operational Benefits Realization

2 The Program realizes operational benefits when meters fitted with SmartMeter™  
3 technology are installed, transitioned, and activated.

4 Following installation, PG&E transitions gas and electric meters to wireless reads  
5 and billing when: (1) the meters are installed and capable of wireless reads and billing;  
6 (2) the communications network infrastructure is in place to remotely read the meters;  
7 and (3) the remote meter reads become stable and reliable for billing purposes.

8 Once enough customers on a particular “route string” transition to SmartMeter™ billing,  
9 manual reading of the meters on that “route string” ceases, at which point those meters  
10 are considered “activated.”

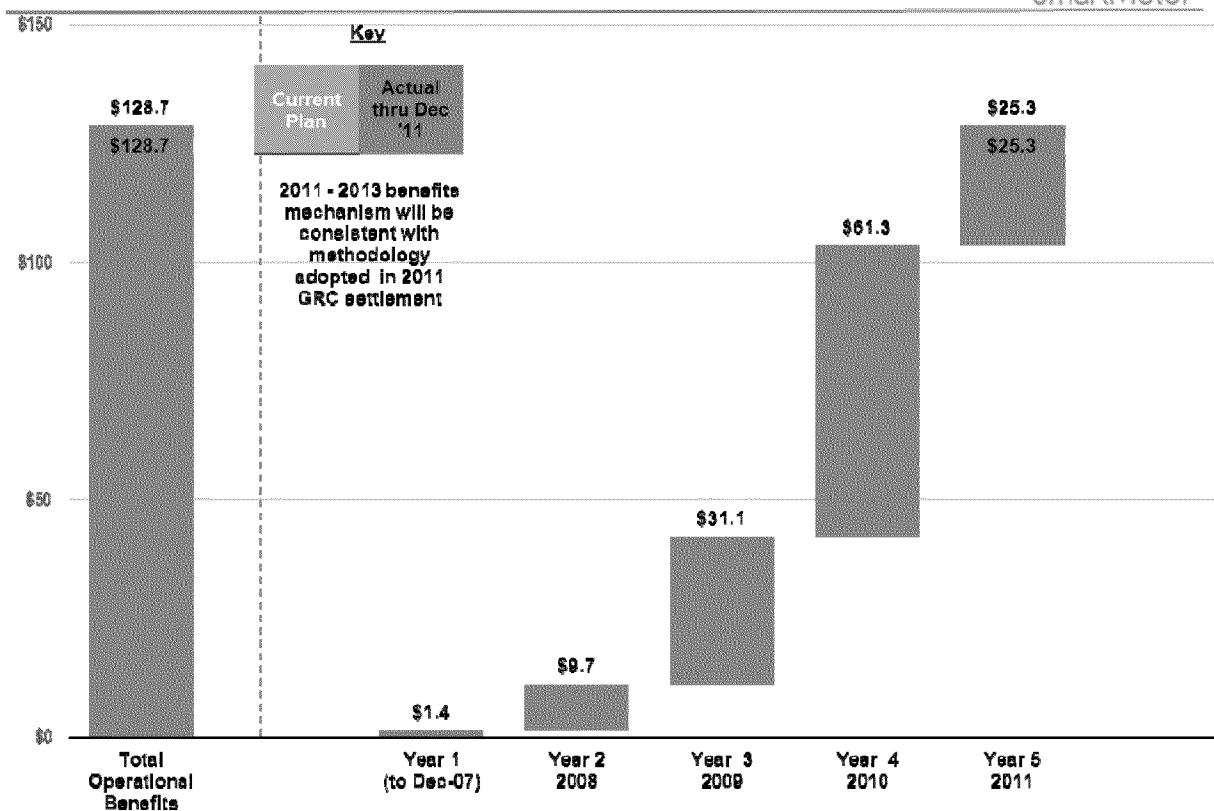
11 As reported in the Company’s January 2008 Report, the first meter activations  
12 occurred in December 2007. Through 2011, approximately 8,638,000 meters have  
13 been transitioned, and approximately 5,042,000 meters have been activated, with  
14 \$128.7 million corresponding cumulative benefits recorded as credits to the balancing  
15 accounts. Such amounts are consistent with the calculation methodologies and savings  
16 rates adopted in the AMI and Upgrade Decisions, as adjusted by the 2011 General Rate  
17 Case (GRC) Decision 11-05-018.

18 Table III-8 shows activated meters and the corresponding benefits based on the  
19 savings rates adopted in the AMI and Upgrade Decisions. These benefits totaled  
20 \$1.9543 per meter per month for electric and \$1.0366 per meter per month for gas.  
21 Thereafter, the 2011 GRC Settlement was adopted, which set activated meter benefits  
22 at \$0.9225 per meter per month for electric and \$0.0189 per meter per month for gas.  
23 In compliance with the 2011 GRC Settlement, the activated meter benefits were  
24 adjusted effective January 1, 2011, the largest adjustment of which was the removal of

1 meter-reading savings that are now reflected in a new Meter Reading Balancing  
 2 Account (MRBA).

3 **Table III – 8**

Total Operational Benefits by Year (\$ Millions)



4

Activated Meter Benefit - Current Forecast (As of December 31, 2011)						
		Year 1*	Year 2*	Year 3*	Year 4	Year 5
(in thousands)		(To Dec-07)	(CY 2008)	(CY 2009)	(CY 2010)	(CY 2011)
<b>Meters</b>						
Activated Electric meter months		50	1,436	6,669	17,495	26,812
Activated Gas meter months		21	2,086	12,666	21,341	28,314
Total Activated meter months		71	3,521	19,335	38,836	55,127
<b>SmartMeter Balancing Account</b>						
Electric at \$1.77 per meter month	\$1.77	\$89	\$2,544			
Electric at \$1.95 per meter month	\$1.95			\$12,925	\$34,191	-
Gas at \$1.04 per meter month	\$1.04	\$22	\$2,162	\$13,129	\$22,122	-
Electric at \$0.92 per meter month		-	-	-	-	\$24,734
Gas at \$0.02 per meter month		-	-	-	-	\$535
Reduced Software Licensing		\$1,251	\$5,000	\$5,000	\$5,000	-
Automate Interval Billing		-	-	-	-	-
		\$1,362	\$9,706	\$31,054	\$61,313	\$25,269

5 Note: Totals subject to rounding

1 **IV. System Performance Criteria Metrics**

2 System performance criteria and metrics are measured and reported on an ongoing  
3 basis. As stated in previous reports, PG&E may modify these criteria and metrics after  
4 it has collected and analyzed actual system performance parameters in order to better  
5 characterize system performance.

6 In Table IV-1, PG&E has summarized SmartMeter™ Program Data metrics for  
7 timely and estimated bills for the third and fourth quarters of 2011.

8 **Table IV – 1**

9

Timely Bills			Estimated Bills		
Month	Overall	SmartMeter	Month	Overall	SmartMeter
July 11	99.78%	99.87%	July 11	0.40%	0.09%
August 11	99.85%	99.91%	August 11	0.39%	0.10%
September 11	99.88%	99.93%	September 11	0.39%	0.09%
October 11	99.89%	99.94%	October 11	0.38%	0.06%
November 11	99.89%	99.95%	November 11	0.33%	0.05%
December 11	99.89%	99.95%	December 11	0.33%	0.04%
Total % of Service Agreements (SAs) Billed ≤ 35 Days as compared to all active SA's.			Number of bill segment calculations based on estimated usage as a % of all completed bill segments.		

10

11 The performance criteria presented in Table IV-2 are based on the number of actual  
12 reads retrieved by the head-end system versus the expected number of reads provided  
13 by the head-end system. Deployment in areas with poor communications coverage  
14 degrades performance, while firmware upgrades and supplemental network designs for  
15 existing and new installations improve performance.<sup>7</sup> PG&E considers that the system  
16 performs as designed within the specified system requirements. Additionally, PG&E's  
17 monitoring of SmartMeter™ billing continues to indicate performance that meets and/or  
18 exceeds established criteria.

<sup>7</sup> As noted earlier, customers' delay in accepting their SMs, as represented in the Extended Delay List, already has reduced connectivity (i.e., degraded the RF-network) in some cases. In addition, opt-outs from the SmartMeter™ Program will degrade the RF-network and its performance, and will therefore require reinforcement.

1 **Table IV – 2**

Performance Criteria	Jul'11 thru Dec'11	Jan'11 thru Jun'11	Jul'10 thru Dec'10	Jan'10 thru Jun'10	Jun'09 thru Dec'09	Jan'09 thru Jun'09
1. Electric module failure rate	0.27%	0.42%	0.45%	0.09%	0.34%	0.12%
2. Gas module failure rate	0.11%	0.27%	0.09%	0.14%	0.36%	0.45%
3. Electric network failure rate	0.19%	0.52%	0.35%	0.23%	0.63%	0.29%
4. Gas network failure rate	0.95%	0.65%	0.13%	0.14%	0.34%	0.24%
5. Electric billing data collection failure rate	0.15%	0.23%	0.27%	0.39%	1.14%	0.81%
6. Gas billing data collection failure rate	0.36%	0.29%	0.23%	0.16%	0.22%	0.20%

2

3 The definitions of the system performance criteria presented in Table IV-2 are as  
4 follows:

5 *Electric module failure rate:* This rate represents the incidence of meters removed  
6 specifically for suspected meter hardware failures (such as blank displays,  
7 meter/module hardware errors, and non-communicating meters). This rate does not  
8 count external causes (e.g., broken covers, customer-damaged meters, or  
9 tampering/theft). Meters removed for suspected meter hardware failures are  
10 investigated through the Return Material Authorization (RMA) process.

11 *Gas module failure rate:* This rate represents the incidence of modules removed  
12 specifically for suspected hardware failures (such as bad battery/poor charging patterns,  
13 bad module circuits, and non-communicating modules). This rate does not count  
14 external causes (e.g., customer-damaged meters, scheduled meter changes, or dog-  
15 caused damage). Modules removed for suspected hardware failures are investigated  
16 through the RMA process.

17 *Electric network failure rate:* This rate represents the incidence of network  
18 components removed and submitted for RMA (such as APs and relays failing to

1 communicate or failing to maintain charging capacity). This rate also includes  
2 component failure in substation communication equipment.

3 *Gas network failure rate:* This rate represents the incidence of gas network  
4 components removed and submitted for RMA (such as components failing to maintain  
5 charging capacity, drifting off frequency, experiencing cellular failures, and experiencing  
6 failed electronic boxes).

7 *Electric billing data collection failure rate:* This rate represents the number of electric  
8 SmartMeters™ from which complete data (complete backhaul data, daily anchor, and  
9 complete set of intervals) were not retrieved, divided by the total number of electric  
10 SmartMeters™. This measure consists of the percentage of complete daily data sets,  
11 one good anchor read and complete good interval reads, averaged over the defined  
12 period. Any service point with an estimated anchor and/or estimated interval read(s)  
13 fails this measure and is excluded. Failure of this read metric does not lead to an  
14 estimated bill; an accurate bill can be generated in most cases.

15 *Gas billing data collection failure rate:* This rate represents the number of gas  
16 SmartMeters™ from which a daily cumulative read was not retrieved, divided by the  
17 total number of gas SmartMeter™ devices. Failure of this read metric does not lead to  
18 an estimated bill; an accurate bill can be generated in most cases.

## 19 **V. Customer Interest in Accessing Real-Time Usage and Pricing Information**

20 PG&E launched its residential critical peak pricing program, SmartRate™, in May  
21 2008. This program encourages customers to manage energy usage during particularly  
22 hot summer days, when SmartDay™ events are triggered. As of December 31, 2011,  
23 the SmartRate™ Program had approximately 22,000 active residential customers.

1 Decision 10-02-032, which adopted Peak Day Pricing (PDP), ordered 172  
2 SmartRate™ small to medium businesses to transition to PDP as of May 1, 2010. The  
3 decision also ordered residential customers on SmartRate™ to default to PDP as of  
4 February 1, 2011. PG&E requested, and the CPUC granted, an extension to  
5 November 1, 2011 for this transition. More recently, in Decision 11-11-008, the CPUC  
6 again deferred this transition while it sets its long-term policy for residential dynamic  
7 pricing.

8 In 2010, PG&E made changes to its SmartRate™ marketing strategy to account for  
9 the program ending in 2010 and the CPUC's decision to default all SmartRate™  
10 customers to PDP in February 2011. Given the differences between SmartRate™ and  
11 PDP, as well as uncertainty in the ultimate characteristics of the pending PDP program,  
12 PG&E adjusted the focus of SmartRate™ outreach to maintaining its current population  
13 of program participants. SmartRate™ customers received both a welcome-back letter  
14 and retention mailer. The welcome-back letter reminded customers about the start of  
15 the season and provided information to allow customers to update their notification  
16 sources. The retention mailer included customer-centric tips for event days. PG&E  
17 also communicated with customers when notifications were unsuccessful to obtain  
18 updates to notification contact information.

19 In April 2012, PG&E will publish its 2011 Load Impact Evaluation report for the  
20 Residential SmartRate™, PDP, Time-Of-Use Tariffs, and SmartAC™ Programs, which  
21 will provide details on the 2011 season performance of the SmartRate™ population.

22 Preliminary findings include:

- 23 ■ There were 15 SmartDays™ during the 2011 season (conducted from May 1  
24 through October 31).



- 1       ▪ On average, participants reduced peak electricity use by 13 percent across the  
2       15 event days.
- 3       ▪ June's two event days offered the season's highest average reduction of 15  
4       percent.
- 5       ▪ In general, participants with central air conditioning reduced peak electricity use  
6       more (approximately 23 percent) than those without it.
- 7       ▪ 86 percent of SmartRate™ respondents report being very satisfied with  
8       SmartRate™.
- 9       ▪ A higher portion of low-income customers indicated high levels of satisfaction  
10      compared to non-low-income respondents (90 percent versus 83 percent).
- 11      ▪ 83 percent of respondents perceived they were saving energy during their  
12      SmartRate™ participation and 82 percent of those thought they experienced a  
13      lower bill.
- 14      ▪ 90 percent of respondents plan to continue on SmartRate™.
- 15      ▪ 88 percent of respondents would recommend SmartRate™ to a friend, and 60  
16      percent have done so.

17      During the 2011 event season, PG&E focused on retaining existing SmartRate™  
18      customers, and also attempted to recruit new customers in connection with the  
19      deployment of SmartMeters™ to improve demand response and customer satisfaction.  
20      This new campaign solicited tips from participants concerning how to reduce peak  
21      demand (and associated electric bills) by offering a chance to win a prize with their  
22      submission. These tips were also communicated to customers through SmartDay™  
23      event notifications to timely encourage customers to respond to the price signals.

1 As noted above, in November 2011, the CPUC granted PG&E's request to retain  
2 SmartRate™ as a residential tariff option until the Commission decides on an alternative  
3 set of rates, which may include some combination of PDP, PTR, and other programs.  
4 Given this greater certainty that the SmartRate™ program will continue, PG&E plans to  
5 resume broad customer acquisition efforts in 2012.

## 6 **VI. SmartMeter™ Information Technology Progress**

7 The SmartMeter™ Program established the SmartMeter™ Technology Completion  
8 Project (SMTCP) in the spring of 2011 to consolidate its remaining individual  
9 SmartMeter™ IT projects, including performance enhancement efforts, into a single  
10 effort. Centralized project management of the remaining IT efforts resulted in a  
11 focused, streamlined and financially-efficient solution delivery.

12 The functionality was delivered in three releases:

- 13 ■ Release 1 - July 2011: Electric Meter Head End System Upgrade;  
14 Performance and Scalability Improvements; and Exception Management  
15 Improvements
- 16 ■ Release 2 - September 2011: Remote Connect and Disconnect; and Outage  
17 Management – Identify and Scope Outages
- 18 ■ Release 3 - November 2011: Momentary Outage Tracking; Additional  
19 Performance and Scalability Improvements; Additional Exception  
20 Management Improvements; Field Service Unit Upgrade; and Net Energy  
21 Metering Management

1 The SMTCP Project was successfully completed and all functionality was  
2 transitioned to Operational Support in December 2011. The SmartMeter™ IT work is  
3 now substantially complete.<sup>8</sup>

#### 4 **VII. Advances in AMI Technology**

##### 5 A. Distribution Automation Update

6 On June 30, 2011, in compliance with Senate Bill 17, PG&E submitted its Smart Grid  
7 Deployment Plan (Application 11-06-029) to the CPUC, sharing PG&E's vision for the  
8 Smart Grid and a broad plan for modernizing its electric grid infrastructure to deliver a  
9 host of energy and cost savings to customers. The plan included proposals by which  
10 PG&E's AMI communications network would support Distribution Automation  
11 applications, including automated distribution reconfiguration and load control.

12 On November 21, 2011, PG&E filed its Smart Grid Pilot Deployment Project,  
13 Application 11-11-017, seeking approval for nine pilot projects that will be used to  
14 evaluate the viability of different technological functionality. As the SmartMeter™  
15 project draws to a close, PG&E expects that the Commission will monitor PG&E's  
16 participation in and reporting on Distribution Automation activities in the Smart Grid  
17 proceeding.

##### 18 B. HAN Update

19 The CPUC continues to encourage development of Home Area Network (HAN)  
20 functionality. In Decision 11-07-056, the Commission ordered PG&E, Southern  
21 California Edison Company, and San Diego Gas and Electric Company to file HAN  
22 "rollout" implementation plans by the end of November 2011, including an initial-phase

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<sup>8</sup> Two IT projects (related to Home Area Network and the Peak Time Rebate program) are deferred, along with their budgeted dollars, until the CPUC determines the scope and timeline for the programs. PG&E was directed to file updated testimony on October 28, 2011. PG&E does not expect Commission decisions on these two matters until later in 2012.

1 rollout of up to 5,000 HAN devices by March 1, 2012.<sup>9</sup> PG&E's HAN Implementation  
2 Plan, filed on November 28, 2011, describes the capabilities and schedule for PG&E's  
3 HAN-enabled programs, including discussion of how standards-development and  
4 market-adoption will affect the plan.

5 C. Technology Industry Updates

6 PG&E continues to lead and participate in industry activities related to advanced  
7 metering and communication networks, including through memberships in professional  
8 organizations and attendance at conventions and trade shows.

9 In late 2011, PG&E responded to the White House's challenge to design a standard  
10 format by which customers could access their energy-usage data online. PG&E  
11 launched the Green Button on December 18, 2011, and is among the first utilities in the  
12 country to empower customers with their own data in this previously-unavailable,  
13 portable format. Making detailed energy-usage information available in a standardized  
14 file format encourages both awareness of energy-consumption and entrepreneurial  
15 innovation for new customer-focused applications.

16 Many vendors have shown significant interest in the Green Button process, and  
17 numerous applications that can process Green Button data are in development. The  
18 next step in the Green Button process is to establish certification, interoperability, and a  
19 common repository for Green Button applications.

20 In the last two quarters of 2011, PG&E representatives delivered presentations at  
21 the Association for Demand Response and Smart Grid (ADS)<sup>10</sup> meeting (July 2011), the

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<sup>9</sup> As of the date of this filing, PG&E has begun implementing its HAN Implementation Plan

<sup>10</sup> The mission of the ADS, a nonprofit organization, is to facilitate the exchange of information and expertise among demand-response practitioners and policy makers.

1 Utilimetrics – Autovation conference (September 2011), and the Grid Interop 2011  
2 conference<sup>11</sup> (December 2011).

3 PG&E actively participates in the following significant groups as part of the  
4 Company’s commitment to an open and interoperable Smart Grid:

- 5 ■ Utility Communications Architecture (UCA)<sup>12</sup> Open Smart Grid Technical Committee  
6 – Providing oversight over UCA’s systems, communications, security, simulations,  
7 and certification and testing working groups. The UCA Open Smart Grid committee  
8 (a utility leadership committee) has been integral in setting utility requirements in  
9 UCA and providing them to the appropriate standards bodies.
- 10 ■ UCA Open Auto DR (Chair) – Transforming the Lawrence Berkeley National  
11 Laboratory Automated Demand Response requirements from a specification to a  
12 standard.
- 13 ■ Smart Energy Profile 2.0 (SEP 2.0) Application Specification – Creating an open  
14 standards-based communication technology to enable two-way communication  
15 between devices and energy service providers. A PG&E representative is the chair  
16 of the Security sub-group for this application protocol specification.
- 17 ■ OpenSG “Green Button” Task Force (Proposed) – Creating an OpenADE/ESPI  
18 based common format to allow users to download their data and share it with third-  
19 party application developers.
- 20 ■ SAE J2847/1 – Setting the communication standards between vehicle and grid for  
21 purposes of energy transfer and defining its mapping to the SEP 2.0 HAN  
22 application standard.

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<sup>11</sup> The Grid Interop Conference convenes industry stakeholders to ensure rapid development and implementation of SmartGrid interoperability standards.

<sup>12</sup> The UCA® International Users Group is a nonprofit corporation consisting of utility user and supplier companies dedicated to promoting the integration and interoperability of electric/gas/water utility systems through the use of international standards-based technology.

- 1   ▪ OpenADR Alliance (A PG&E representative is the treasurer and board member of  
2    this nonprofit corporation) – Fostering the development, adoption, and compliance of  
3    a Smart Grid standard known as Open Automated Demand Response (OpenADR).
- 4   ▪ The National Institute of Standards and Technology (NIST) SmartGrid Testing and  
5    Certification Committee (SGTCC) – Creating and maintaining the necessary  
6    documentation and organizational framework for compliance, interoperability and  
7    cyber-security testing and certification for SGIP-recommended Smart Grid  
8    standards.
- 9   ▪ NIST SGIP<sup>13</sup> – Defining requirements for essential communication protocols and  
10   other common specifications and coordinating development of these standards by  
11   collaborating organizations in a public/private partnership.

12       PG&E continues to believe that making these standards interoperable through a  
13   comprehensive certification process should be one of the industries' highest priorities.  
14   PG&E will continue to work with major industry stakeholders and the above  
15   organizations in assisting with that challenge.

## 16   **VIII. SmartMeter™ Transition to Operations**

17       In 2011, PG&E initiated a program to systematically evaluate all aspects of the  
18   SmartMeter™ Project, to ensure that learned processes and systems will continue after  
19   the Project ends by transitioning them to traditional operations organizations. The effort  
20   was governed by a cross-functional project and business leadership team (Transition  
21   Steering Team), which reviewed and approved recommendations to ensure the  
22   continuing work, knowledge, and benefits of the SmartMeter™ network are fully  
23   integrated within PG&E's normal business.

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<sup>13</sup> The NIST initiated the SGIP to support NIST in fulfilling its responsibility, under the Energy Independence and Security Act of 2007, to coordinate standards development for the Smart Grid.

1 As of December 31, 2011, almost all SmartMeter™ work processes and employees,  
2 including those focused on the remaining SmartMeter™ deployment, have been aligned  
3 under existing PG&E business departments. These departments include Contact  
4 Center Operations, Office Services, Meter to Cash, Service Planning, Gas and Electric  
5 Meter Shop, Restoration, Customer Field Services, Energy Service and Solutions,  
6 Telecommunications, and Gas and Electric Maintenance and Construction. Only a  
7 small SmartMeter™ project-management team remains to manage the remaining  
8 deployment, engineering, and reporting activities.

9 The Transition Steering Team also worked with Information Technology,  
10 Governmental Relations, and Internal and External Communication departments to  
11 ensure employees were well-prepared as the transitions were completed. These efforts  
12 will help ensure the benefits of the SmartMeter™ network will be realized long into the  
13 future.