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

ANN H. KIM
CHISTOPHER J. WARNER

Pacific Gas and Electric Company
77 Beale Street., B30A
San Francisco, CA 94105
Telephone: (415) 973-6695
Facsimile: (415) 973-0516
E-Mail: CJW5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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,

ANN H. KIM
CHRISTOPHER J. WARNER

By: /s/
CHRISTOPHER J. WARNER

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105
Telephone: (415) 973-6695
Facsimile: (415) 973-0516
E-Mail: CJW5@pge.com

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PACIFIC GAS AND ELECTRIC COMPANY

March 30, 2012

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)

PG&E

March 30, 2012

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

I. Executive Summary

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

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

A. Introduction

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

[1] SmartMeter™ is a licensed trademark of SmartSynch, Inc.

[2] 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).

[3] D.06-07-027 at pp. 57-58.

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

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

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

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

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

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[4] See A.11-03-014.

[5] 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.

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

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

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

B. Update on the SmartMeter™ Program

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

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

1. <u>Progress in PG&E's AMI Deployment</u>

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

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

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

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[6] 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.

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

2. Program Costs and Benefits

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

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

3. System Performance Criteria

System performance metrics are provided in Table IV-2.

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

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

5. SmartMeter™ Information Technology Progress

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

6. Advances in AMI Technology

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

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

7. SmartMeter™ Transition to Operations

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

II. Progress in PG&E's AMI Deployment

A. Overview

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

As of the beginning of 2012, the SmartMeter™ Program has 835,711 remaining meters to exchange. Subject to various outstanding issues, including customers' elections to opt-out of the SmartMeter™ Program pursuant to Decision 12-02-014, the Program's 2012-activities will focus on substantially completing the remaining meter deployment. The deployment schedule is dependent upon the availability of trained resources, an effective supply chain, and access to customer premises to make the necessary changes at each service location. Deployment planning adjustments may be required due to several factors – including customer considerations, supply chain constraints, and labor availability – which could affect the scheduling of meter endpoint installations, including beyond 2012. These undertakings are further complicated by the competing urgency to remove the SmartMeters™ of customers who opt-out of the SmartMeter™ Program, which PG&E has prioritized since the SmartMeter™ Opt-Out Program's February 2012 inception.

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

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

B. Infrastructure Installations

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

Table II - 1

AMI Project Status as of December 31, 2011

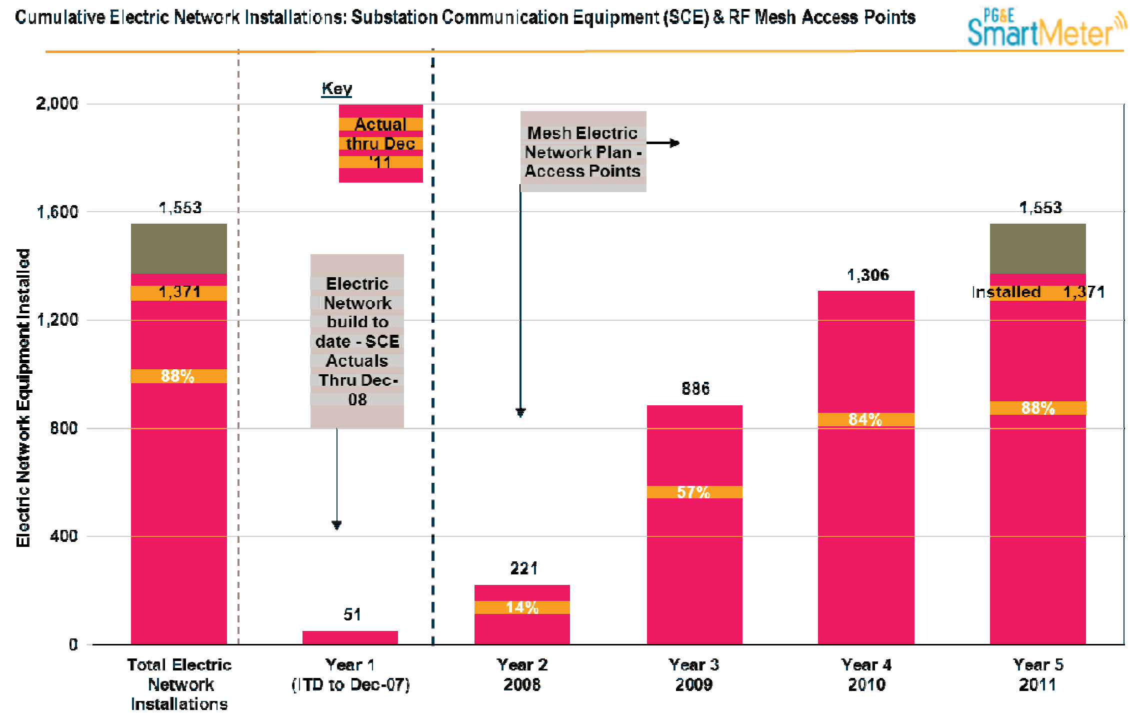
Progress Toward Completion	Total Budgeted Plan	Actual	% of Total Project Plan Installed
Electric Network - RF Network	1,553	1,371	88%
Gas Network Collectors	5,000	4,815	96%
Electric Network Enabled Locations	5,260,391	5,260,391	100%
Electric Meter Installations*	5,630,886	5,074,494	90%
Electric Meters 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 occuring in 2011 and 2012 was funded in the 2011 GRC Decision and is not included in the above table.

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.

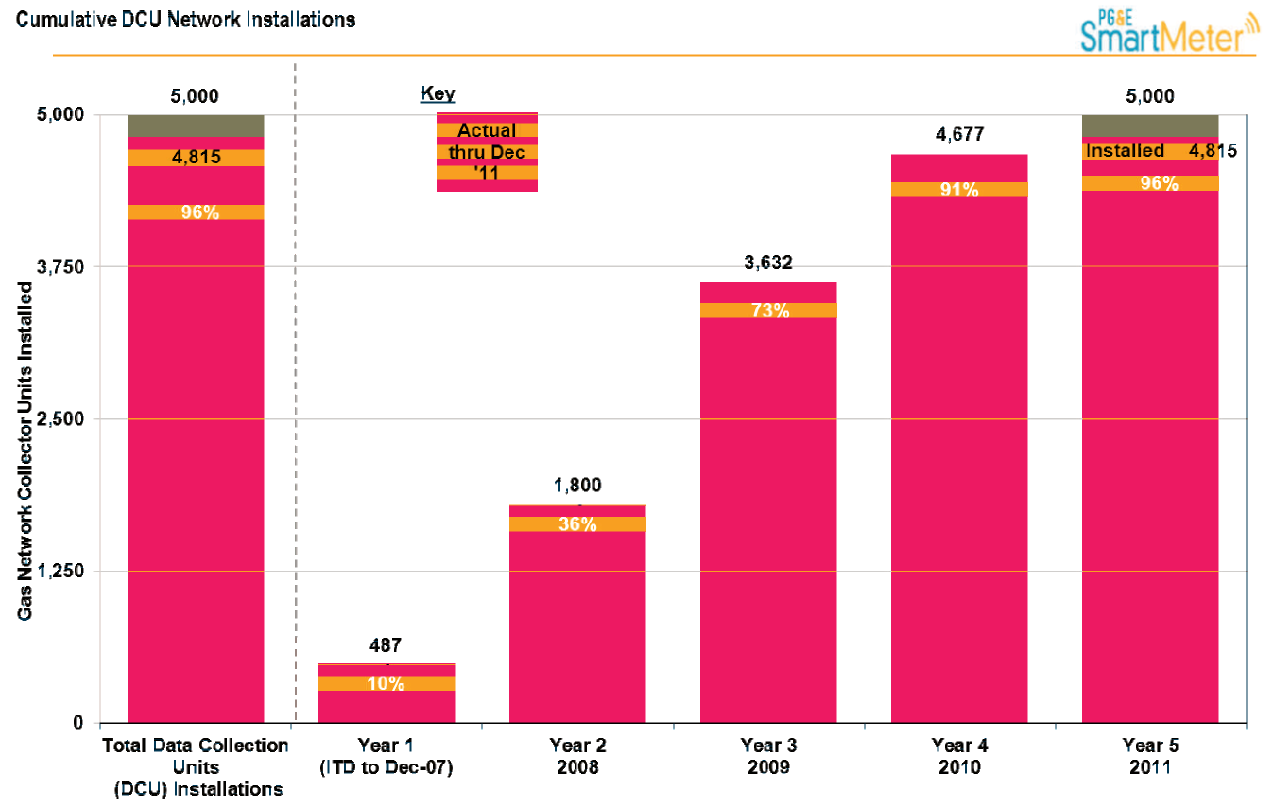
Table II – 2



Electric Network - Substation SCE	Total	Yr 1 (to Dec-07)
Cumulative Installed thru 12/11	51	51
Plan	51	51

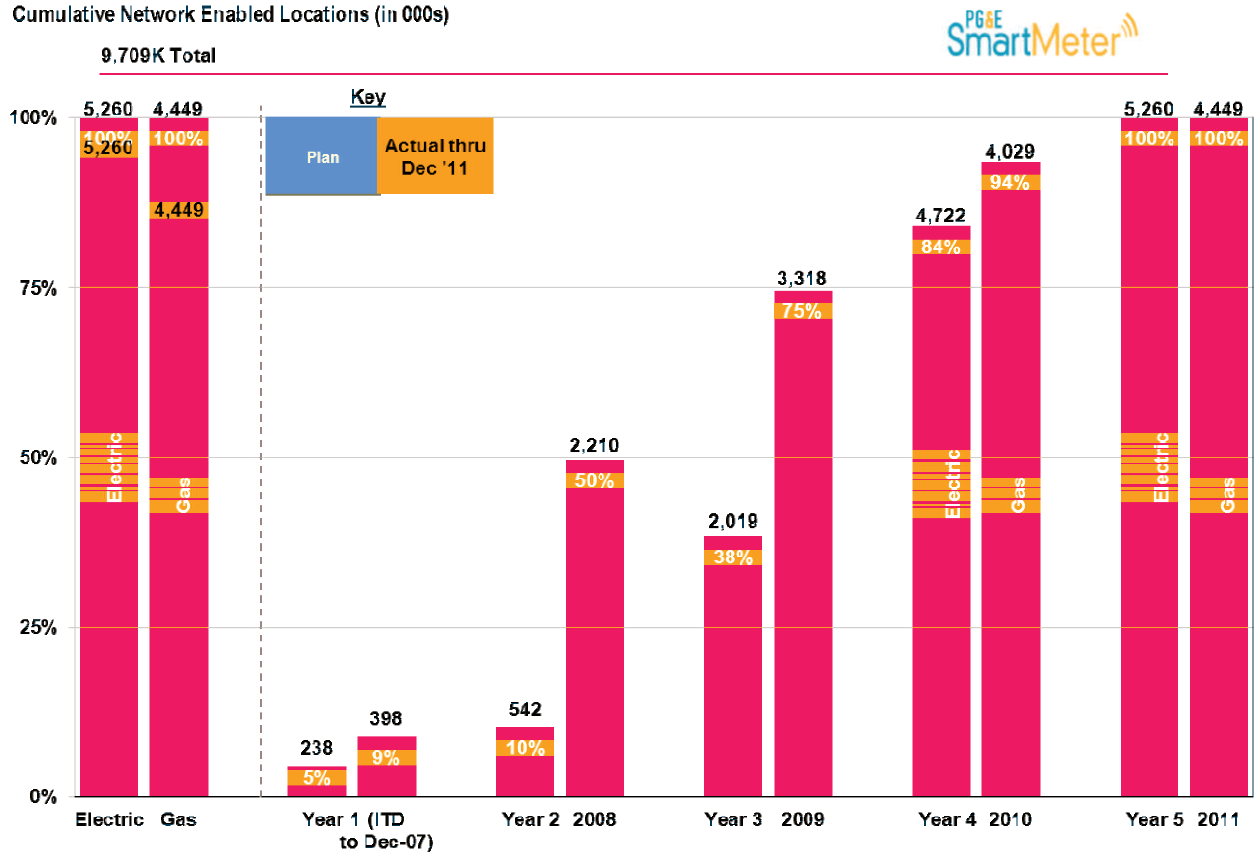
Electric Network - RF Mesh Access Points	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Cumulative Installed thru 12/11	1,371	-	221	886	1,306	1,371
Plan	1,553	-	221	886	1,306	1,553

Table II - 3



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

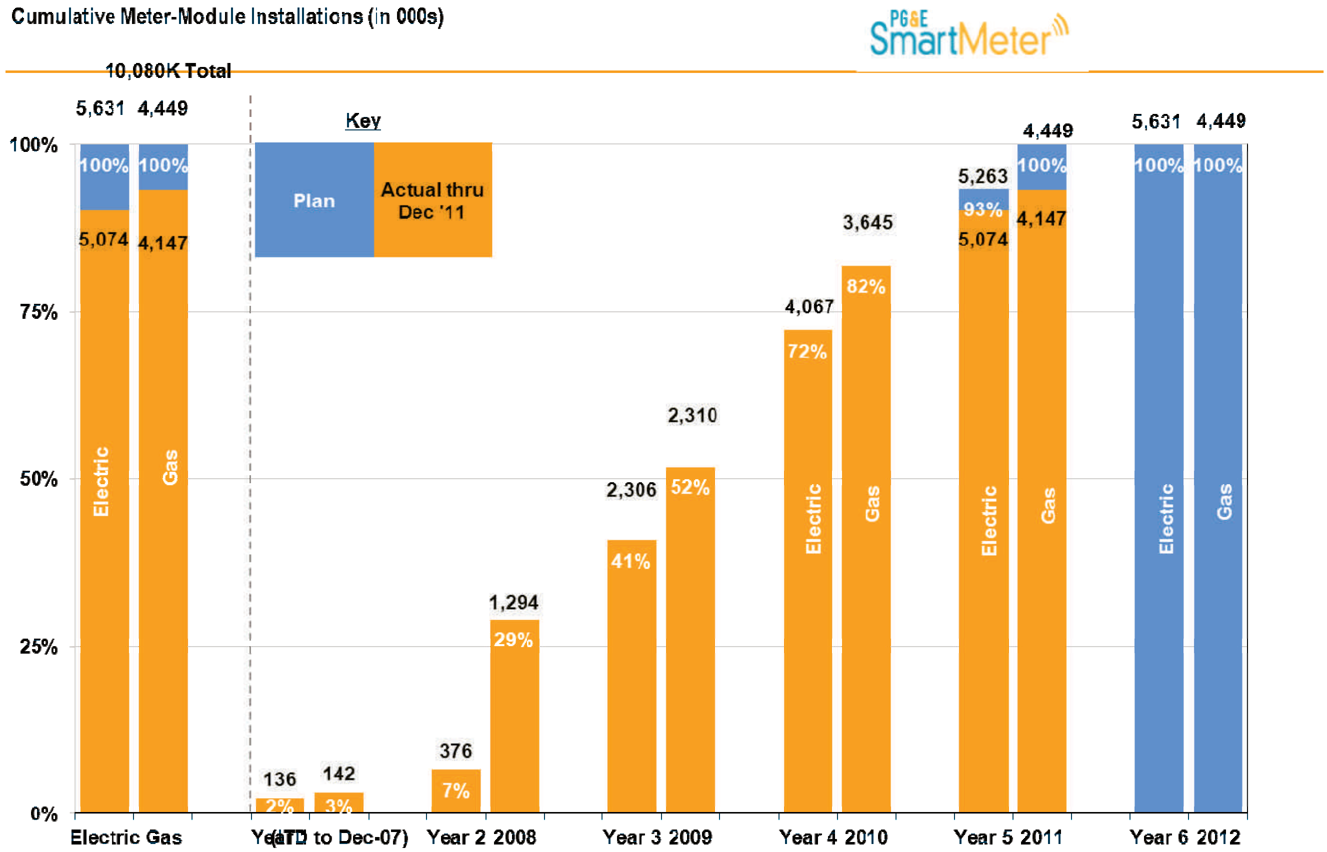
Table II - 4



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

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

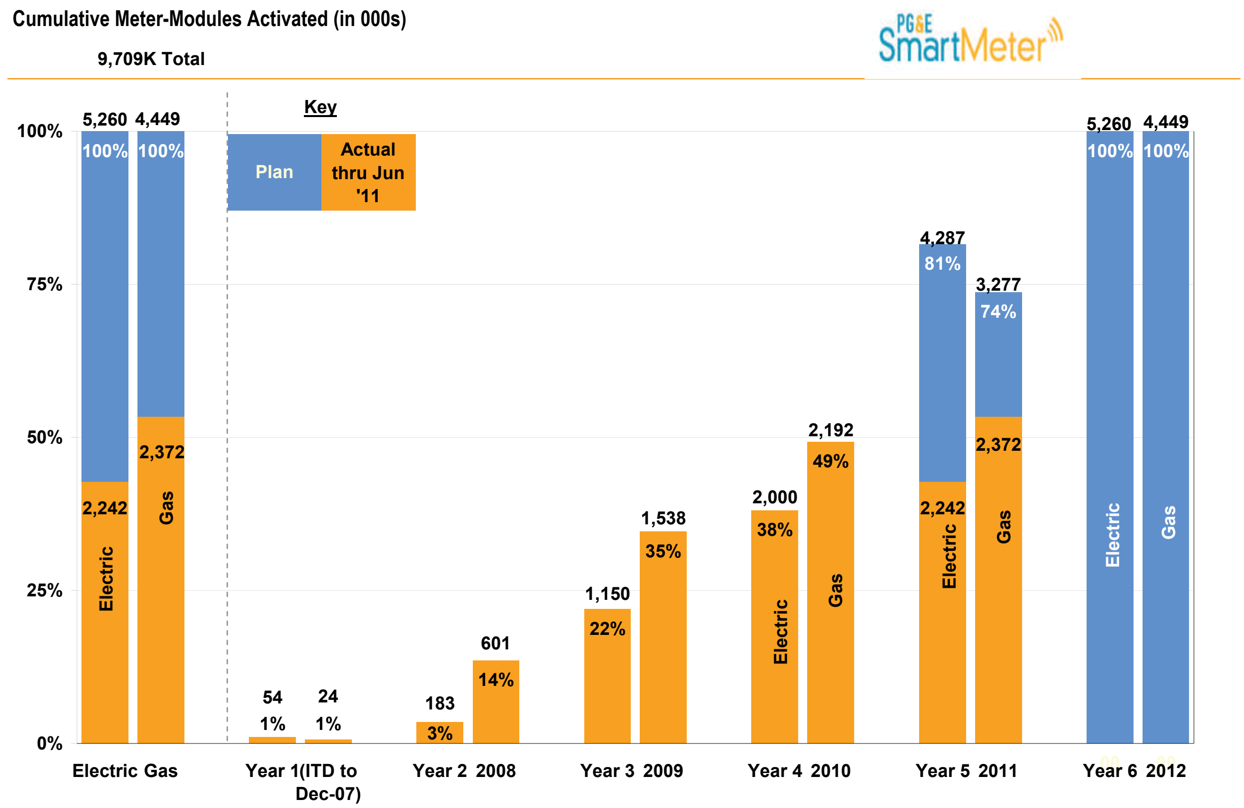
Table II - 5



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.

Table II - 6



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.

III. Program Costs and Benefits

A. SmartMeter™ Program Costs

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

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

Through December 31, 2011, the SmartMeter™ Program incurred costs of approximately $2,219 million ($1,805 million in capital and $414 million in expense). Of this total dollar amount, Field Delivery activities have cost approximately $1,460 million (66 percent) and IT-related activities have cost approximately $478 million (22 percent). The remaining 12 percent is attributed to the Customer & SM Operations and PMO categories. The Program's total estimated cost of $2,335 million is based on the combined CPUC cost authorizations of the AMI Decision ($1,739 million) and Upgrade Decision ($467 million), as well as the additional $129 million of Board-approved shareholder funding.

<u>Table III – 1</u>

($ 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%	

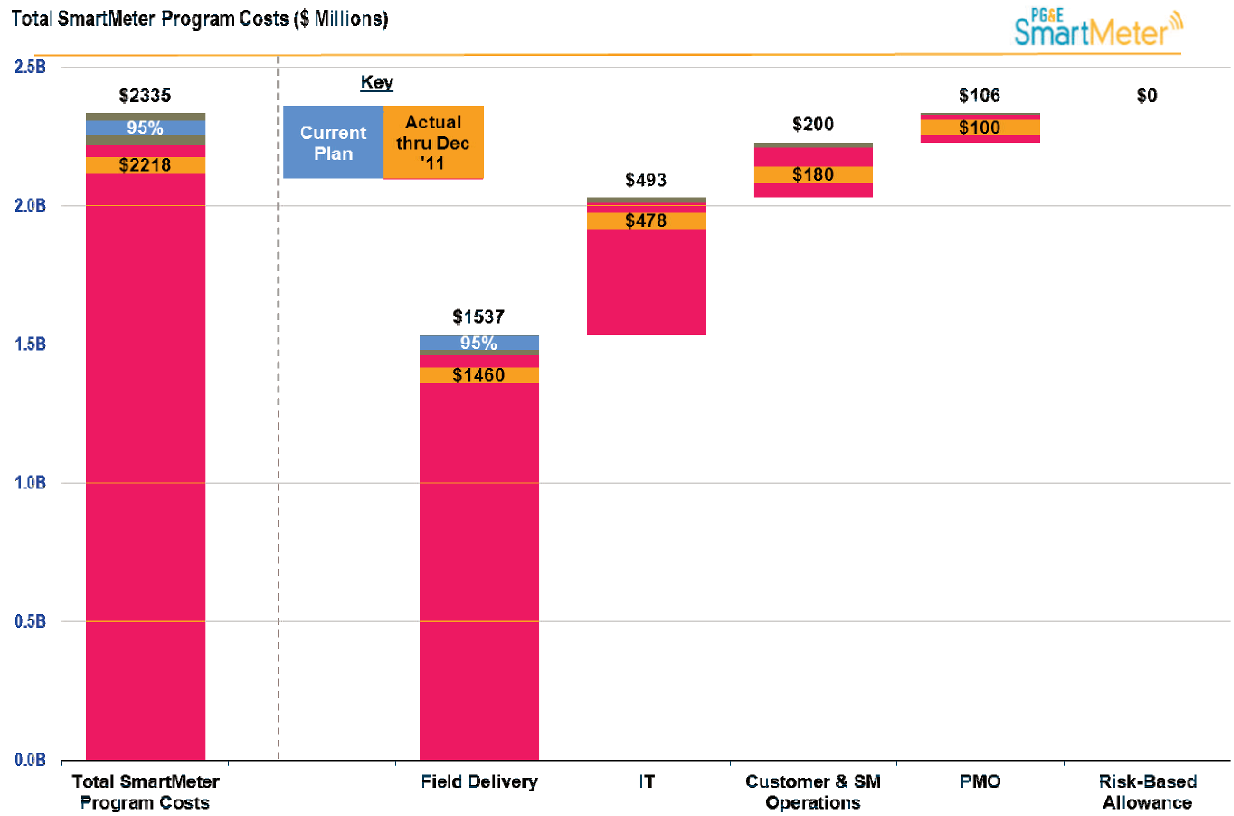
Note: Totals subject to rounding

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

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

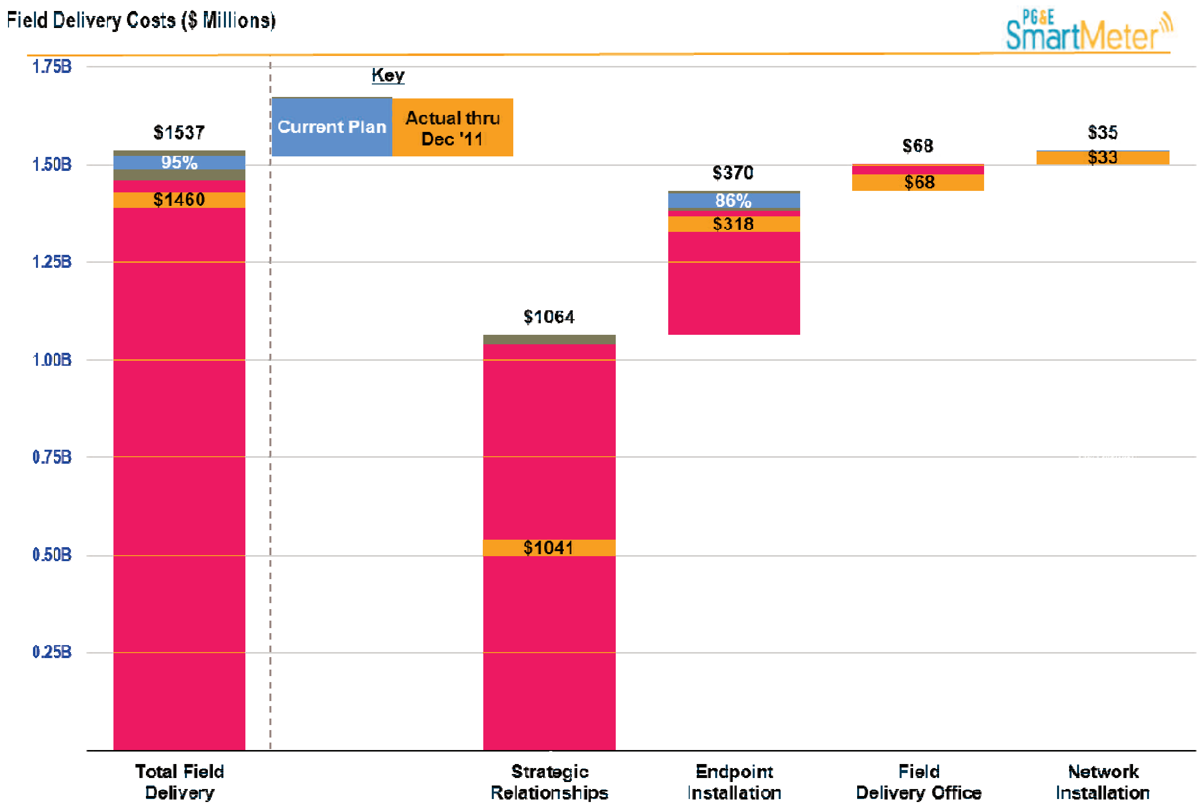
Table III – 2



$ Millions	Total SmartMeter Program Costs	Field Delivery	IT	Customer & SM Operations	PMO	Risk-Based Allow ance
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%	

Note: Totals subject to rounding

Table III– 3

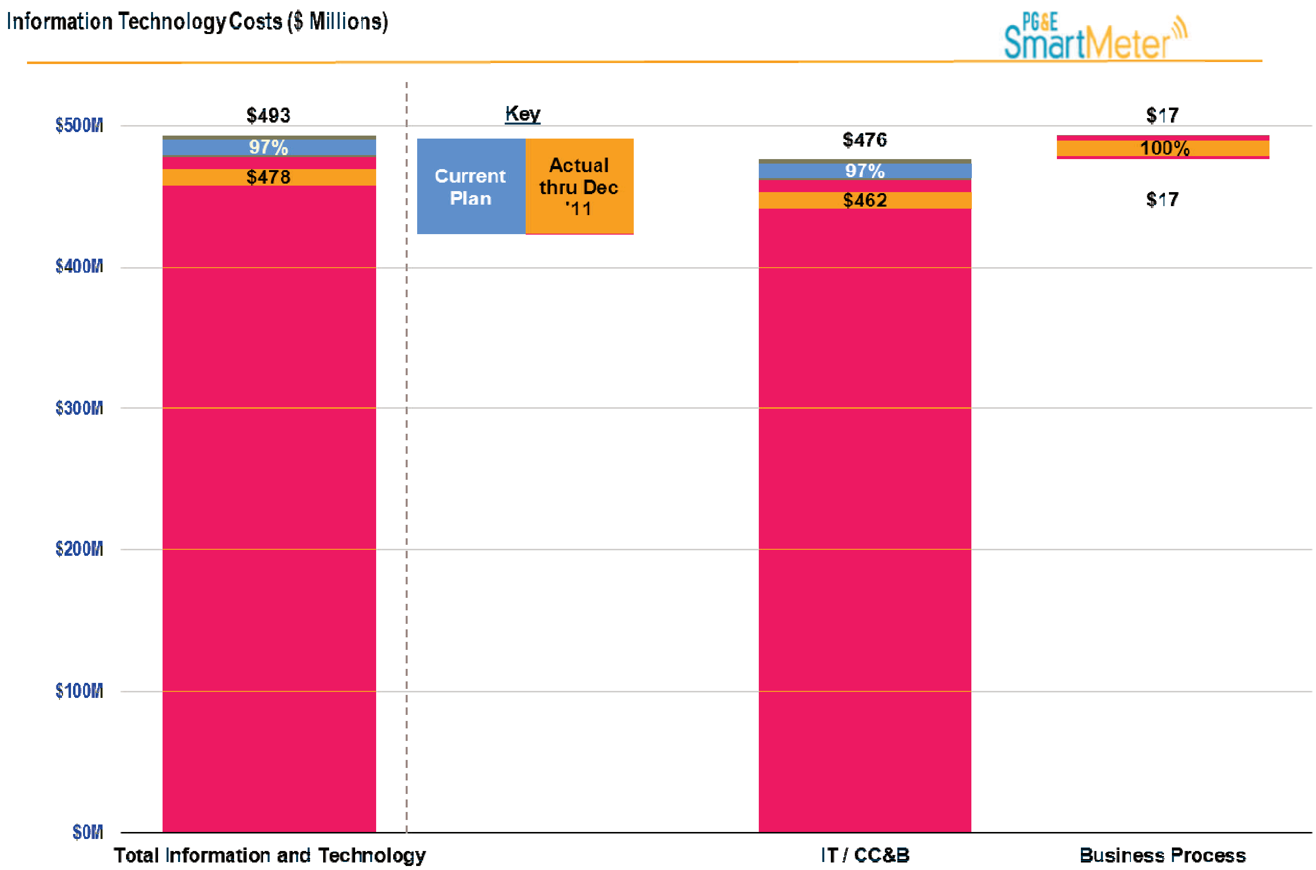


$ Millions	Total Field Delivery	Strategic Relationships	Endpoint Installation	Field Delivery Office	Netw ork Installation
Actuals thru December 31, 2011	1,460	1,041	318	68	33
Plan as of June 30, 2011	1,537	1,064	370	68	35
Cost Changes/Reallocation	-	-	-	-	-
Plan as of December 31, 2011	1,537	1,064	370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

$ Millions	Netw ork Installation	Electric Netw ork	Gas Netw ork
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%

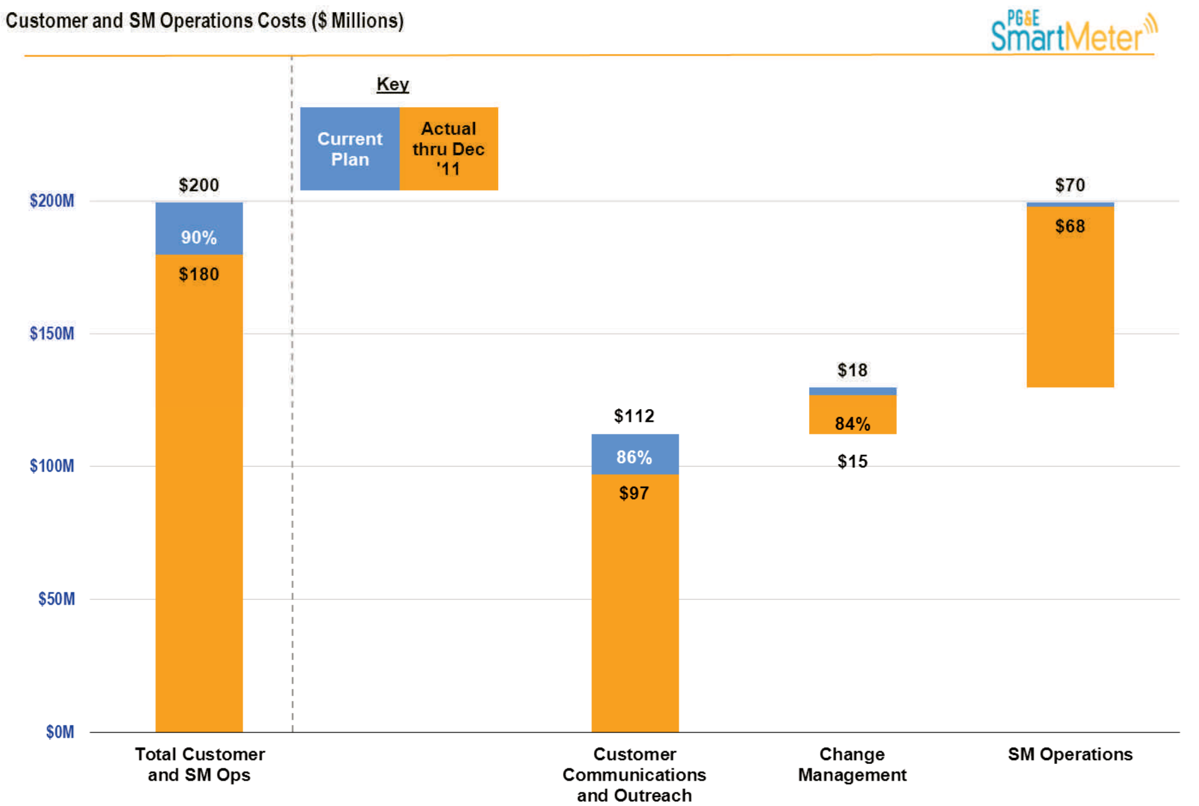
Note: Totals subject to rounding. Some Field Delivery (FD) costs have been reallocated among the FD subcategories to align w ith the project's management of the FD activities.

Table III – 4



$ 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%

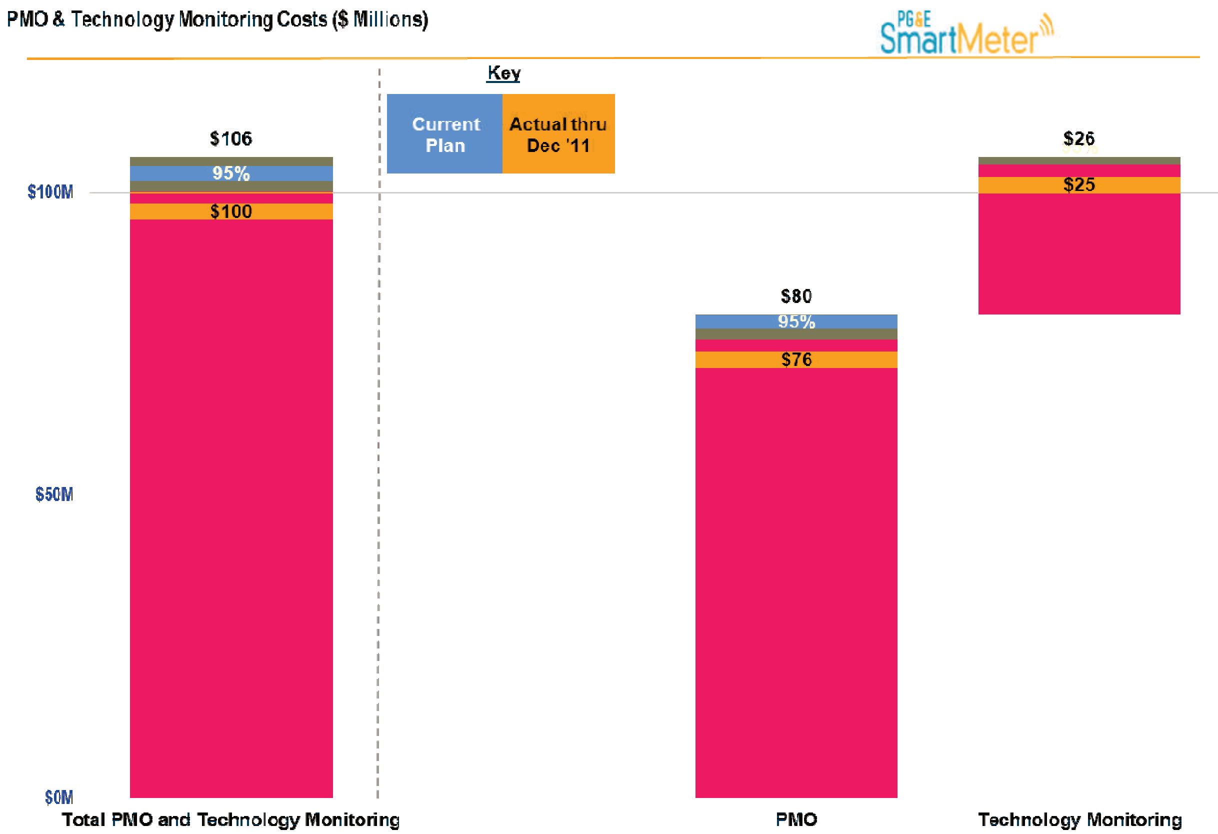
Table III - 5



$ 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%

Note: Totals subject to rounding

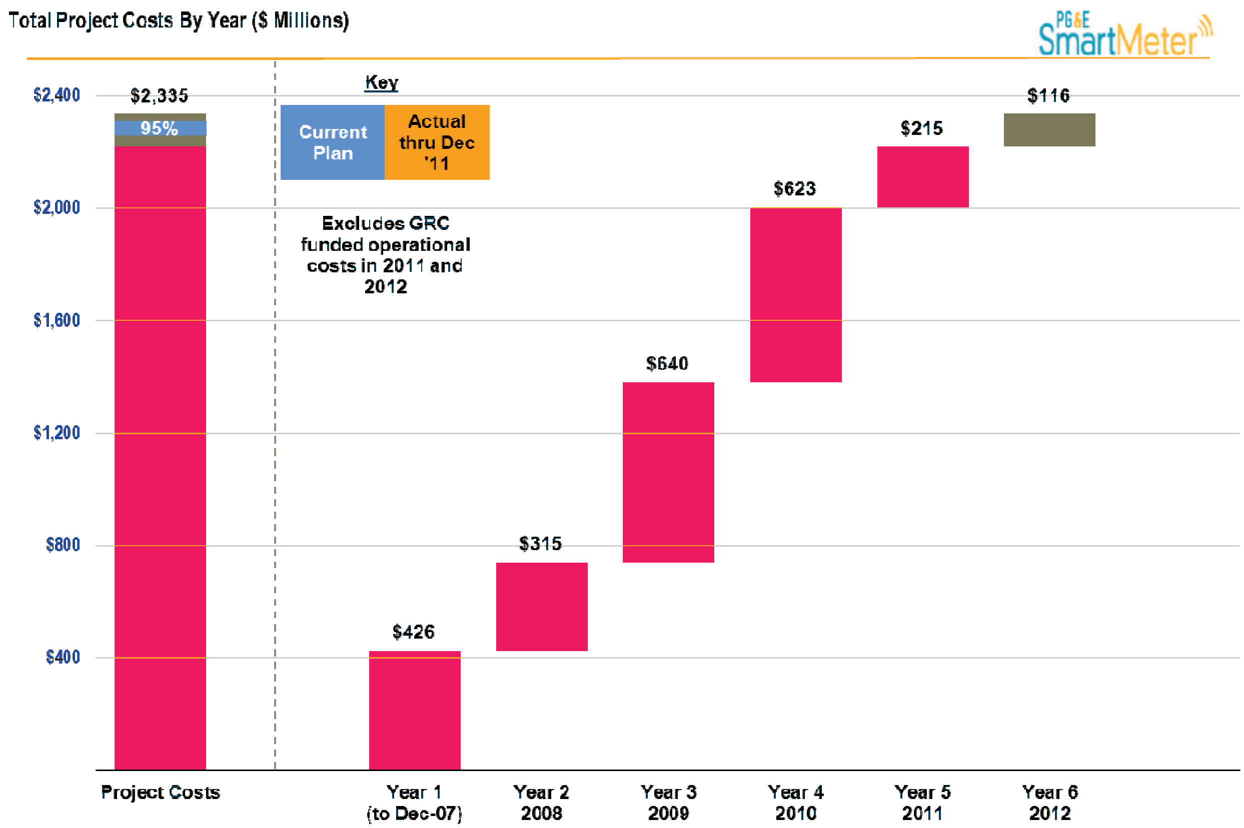
Table III - 6



$ 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%

Note: Totals subject to rounding

Table III – 7



$ 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%

Note: Totals subject to rounding

B. Operational Benefits Realization

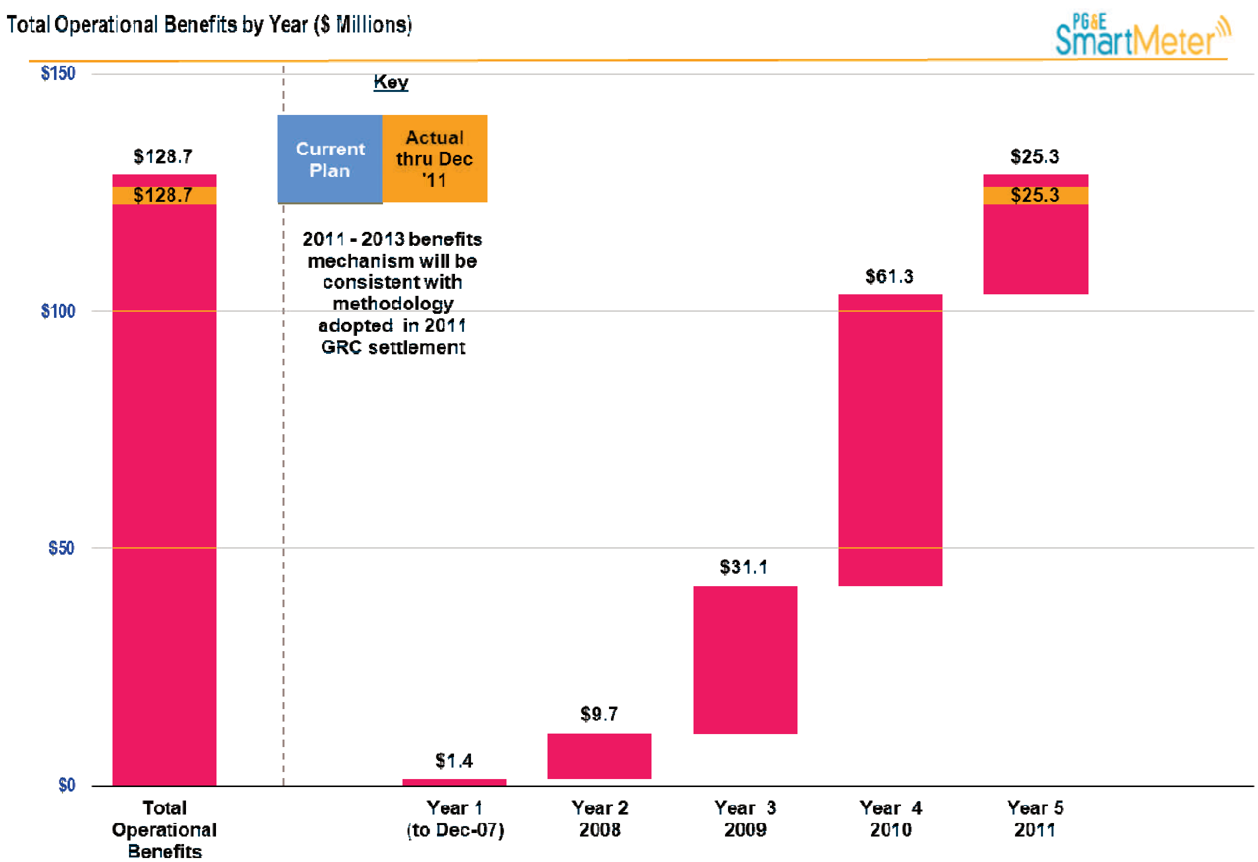
The Program realizes operational benefits when meters fitted with SmartMeter™ technology are installed, transitioned, and activated.

Following installation, PG&E transitions gas and electric meters to wireless reads and billing when: (1) the meters are installed and capable of wireless reads and billing; (2) the communications network infrastructure is in place to remotely read the meters; and (3) the remote meter reads become stable and reliable for billing purposes. Once enough customers on a particular "route string" transition to SmartMeter™ billing, manual reading of the meters on that "route string" ceases, at which point those meters are considered "activated."

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

Table III-8 shows activated meters and the corresponding benefits based on the savings rates adopted in the AMI and Upgrade Decisions. These benefits totaled $1.9543 per meter per month for electric and $1.0366 per meter per month for gas. Thereafter, the 2011 GRC Settlement was adopted, which set activated meter benefits at $0.9225 per meter per month for electric and $0.0189 per meter per month for gas. In compliance with the 2011 GRC Settlement, the activated meter benefits were adjusted effective January 1, 2011, the largest adjustment of which was the removal of meter- reading savings that are now reflected in a new Meter Reading Balancing Account (MRBA).

Table III – 8



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)
Meters						
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
SmartMeter Balancing Account						
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

Note: Totals subject to rounding

IV. System Performance Criteria Metrics

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

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

Table IV – 1

Timely Bills		
Month	**Overall**	**SmartMeter**
July 11	99.78%	99.87%
August 11	99.85%	99.91%
September 11	99.88%	99.93%
October 11	99.89%	99.94%
November 11	99.89%	99.95%
December 11	99.89%	99.95%
Total % of Service Agreements (SAs) Billed ≤ 35 Days as compared to all active SA's.		

Estimated Bills		
Month	**Overall**	**SmartMeter**
July 11	0.40%	0.09%
August 11	0.39%	0.10%
September 11	0.39%	0.09%
October 11	0.38%	0.06%
November 11	0.33%	0.05%
December 11	0.33%	0.04%
Number of bill segment calculations based on estimated usage as a % of all completed bill segments.		

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

[7] 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.

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%

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

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

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

Electric network failure rate: This rate represents the incidence of network components removed and submitted for RMA (such as APs and relays failing to communicate or failing to maintain charging capacity). This rate also includes component failure in substation communication equipment.

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

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

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

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

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

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

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

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

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

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

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

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

VI. SmartMeter™ Information Technology Progress

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

The functionality was delivered in three releases:

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

The SMTCP Project was successfully completed and all functionality was transitioned to Operational Support in December 2011. The SmartMeter™ IT work is now substantially complete.[8]

VII. Advances in AMI Technology

A. Distribution Automation Update

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

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

B. HAN Update

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

[8] 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.

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

C. <u>Technology Industry Updates</u>

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

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

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

In the last two quarters of 2011, PG&E representatives delivered presentations at the Association for Demand Response and Smart Grid (ADS)[10] meeting (July 2011), the

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[9] As of the date of this filing, PG&E has begun implementing its HAN Implementation Plan

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

Utilimetrics – Autovation conference (September 2011), and the Grid Interop 2011 conference[11] (December 2011).

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

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

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[11] The Grid Interop Conference convenes industry stakeholders to ensure rapid development and implementation of SmartGrid interoperability standards.

[12] 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.

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

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

VIII. SmartMeter™ Transition to Operations

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

[13] 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.

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

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