



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

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

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

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**THIRTEENTH SEMI-ANNUAL ASSESSMENT REPORT
ON THE DEPLOYMENT OF PACIFIC GAS AND
ELECTRIC COMPANY'S ADVANCED METERING
INFRASTRUCTURE PROGRAM AND THIRTEENTH
QUARTERLY REPORT ON THE IMPLEMENTATION
PROGRESS OF THE SMARTMETER™ PROGRAM
UPGRADE**

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PACIFIC GAS AND ELECTRIC COMPANY

Dated: April 2, 2013

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UPGRADE**

Pacific Gas and Electric Company (PG&E) submits the attached Thirteenth Semi-Annual Assessment Report on the deployment of its Advanced Metering Infrastructure (AMI) Program and the Thirteenth 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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By: _____ /s/
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Pacific Gas and Electric Company
Advanced Metering Infrastructure Semi-Annual Assessment Report
SmartMeter™ Program Quarterly Report
July 1 – December 31, 2012

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



Date of Filing: April 2, 2013

1 **Pacific Gas and Electric Company**
2 **Advanced Metering Infrastructure Semi-Annual Assessment Report**
3 **SmartMeter™ Program Quarterly Report**
4 **July 1 – December 31, 2012**

5 **I. Executive Summary**

6 This is Pacific Gas and Electric Company's (PG&E or the Company) thirteenth semi-
7 annual assessment report (Report) regarding the deployment of PG&E's Advanced
8 Metering Infrastructure (AMI) Program (now the SmartMeter™¹ Program) and serves as
9 the fifteenth quarterly report for the SmartMeter™ Program Upgrade.² This Report
10 reflects the period from July 1, 2012 through December 31, 2012.

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

16 **A. Introduction**

17 PG&E's SmartMeter™ Program is the largest installation of advanced meters in
18 North America, with 9.5 million electric and gas SmartMeters™ installed as of
19 December 31, 2012. Playing a foundational role in modernizing the electric grid,
20 SmartMeters™ in California are a critical part of statewide policy to better manage

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.

1 energy, and to create the smarter grid that the State needs to incorporate more
2 renewable resources, deliver cleaner energy, and realize the State's ambitious energy
3 efficiency goals.

4 More recently, PG&E has pioneered an "opt-out" alternative⁴ for customers who do
5 not wish to have SmartMeters™ and has launched the Green Button, a means for
6 customers to download their energy-usage data in a standard format.

7 B. Update on the SmartMeter™ Program

8 PG&E's SmartMeter™ Program is nearing the completion of the objectives that the
9 Commission outlined in the AMI and Upgrade Decisions. This section of the Report
10 provides an overview of Program developments and PG&E's progress on individual
11 elements of the Program during the last six months of 2012.

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

13 As of December 31, 2012, PG&E had installed 9.5 million gas and electric
14 SmartMeters™ (including retrofits⁵) – far and away the largest AMI-deployment in North
15 America – and the associated network equipment and information technology (IT)
16 necessary to operate PG&E's SmartMeter™ system. Specifically, as of December 31,
17 2012, approximately 9,525,000 meters (approximately 5,260,000 electric and 4,265,000
18 gas meters) have been converted to, or replaced with, SmartMeter™ technology,
19 representing approximately 95 percent of the total PG&E meter population. Of this
20 number, PG&E has "activated" approximately 6,134,000 meters and recorded
21 \$161.1 million of benefits to the gas and electric SmartMeter™ balancing accounts.

22 PG&E continues to deploy solid-state electric meters communicating over a radio
23 frequency (RF) mesh network, and gas modules communicating over an RF network.

⁴ See A.11-03-014 and D.12-02-014. As of the time of this filing, roughly 35,300 customers are enrolled in the SmartMeter™ Opt-Out Program.

⁵ PG&E installed 370,500 first-generation SmartMeters™ between March 2006 and December 2008.

1 The deployment of the RF Mesh network was planned to consist of an initial phase to
2 deploy Access Points (APs) at defined locations throughout PG&E's service territory,
3 followed by subsequent phases to deploy additional APs to strengthen the network
4 where required. As of December 31, 2011, PG&E had installed all of the 11,379 electric
5 network devices (APs and Relays) and 4,815 gas network data collection units (DCUs)
6 anticipated for the SmartMeter™ Program.⁶

7 Further details of the SmartMeter™ Program's deployment status are provided in
8 Section II of the Report. Further details of the SmartMeter™ Program's cost and benefit
9 status are detailed in Section III of this Report.

10 2. Program Costs and Benefits

11 In late 2010 and early 2011, the SmartMeter™ Program Management Office (PMO)
12 performed a detailed review of all workstream forecasts. The Program sought and
13 received approval in February 2011 from PG&E's Board of Directors to exceed the cost-
14 cap that the CPUC authorized and to spend up to \$2,335 million to complete the
15 Program, with \$39 million to be borne by Company shareholders. As reported in its
16 financial disclosures, PG&E recorded an earnings reserve of \$36 million, representing
17 the current forecast of capital-related costs by which the Company expects to exceed
18 the CPUC-authorized cost cap. PG&E will continue to update its forecasts as the
19 Program continues and may incur additional costs.

20 As of June 30, 2012, PG&E had allocated the entire \$2,335 million Board-authorized
21 program amount to Program workstreams, and the PMO continues to monitor actual
22 spending against the Board-approved forecast, as well as monitor issues and risks that

⁶ Note that although PG&E has deployed all of the network equipment that it anticipated, there may be unique, individual locations requiring modifications to optimize performance. In addition, the CPUC has authorized PG&E to install additional network equipment under its SmartMeter™ Opt-Out Program to maintain communications system integrity.

1 could contribute to potential cost overruns. SmartMeter™ Program expenditures
2 through December 31, 2012 totaled approximately \$2,293 million.

3 3. System Performance Criteria

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

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

6 PG&E launched its SmartRate™ Program in May 2008. As of December 31, 2012,
7 the SmartRate™ Program had 79,633 active and pending residential customers.

8 Details of the SmartRate™ Program are provided in Section V of this Report.

9 5. Advances in AMI Technology

10 PG&E continues to monitor metering and network collector technologies as the AMI-
11 industry advances. PG&E also continues to participate in industry activities related to
12 advanced metering and communication networks, as well as monitor announcements
13 and activities that are significant in the industry, as reported in Section VII of this Report.
14 These activities allow PG&E to stay actively involved in and aware of industry
15 developments.

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

17 A. Overview

18 In 2011, PG&E substantially completed its deployment of necessary network-
19 infrastructure and its development of necessary IT to support the SmartMeter™
20 Program. In 2012, PG&E continued to deploy SmartMeter™-endpoints, installing
21 approximately 116,000 gas and 165,000 electric SmartMeters™, as well as upgrade
22 178 first-generation electric meters.

23 Subject to various outstanding issues, including customers' elections to opt-out of
24 the SmartMeter™ Program, the Program's 2012-13 activities will focus on substantially

1 completing the remaining meter deployment. The deployment schedule is dependent
2 upon the availability of trained resources, an effective supply chain, and access to
3 customer premises to make the necessary changes at each service location, variations
4 in which could affect the scheduling of meter endpoint installations. These undertakings
5 are further complicated by the competing urgency to remove the SmartMeters™ of
6 customers who opt-out of the SmartMeter™ Program, which PG&E has prioritized since
7 the SmartMeter™ Opt-Out Program's inception.

8 PG&E launched its SmartMeter™ Opt-Out Program on February 1, 2012,
9 immediately following the CPUC's issuance of Decision 12-02-014. The SmartMeter™
10 Opt-Out Program provides residential customers with the option to choose
11 electromechanical meters instead of SmartMeters™. The Commission has established
12 interim charges for customers electing to opt-out of the SmartMeter™ Program,
13 specifically an initial charge of \$75 and an ongoing monthly charge of \$10 (the CPUC
14 set the opt-out charges for CARE/FERA customers at \$10 upfront and \$5 monthly).

15 The CPUC's decision also ordered a second phase of the proceeding to consider (1)
16 a community-based opt-out alternative and (2) cost recovery, including setting final
17 customer charges. At the Administrative Law Judge's request, PG&E filed legal briefs
18 on community opt-out in July 2012. PG&E filed testimony regarding its cost-recovery in
19 August 2012. Hearings were held on cost-recovery issues in November 2012, with
20 briefs filed in January 2012. The CPUC has stated that it expects to issue its Phase 2
21 decision in 2013.

22 B. Infrastructure Installations

23 As of December 31, 2012, PG&E had installed approximately 9.5 million meters
24 (including retrofits) with SmartMeter™ technology. PG&E has deployed approximately

1 364,300 retrofit endpoints to replace the Company's first-generation meters, which
 2 relied on PowerLine Carrier (PLC) technology. Tables II-1 through II-4 summarize the
 3 progress of PG&E's SmartMeter™ Program implementation through December 31,
 4 2012.

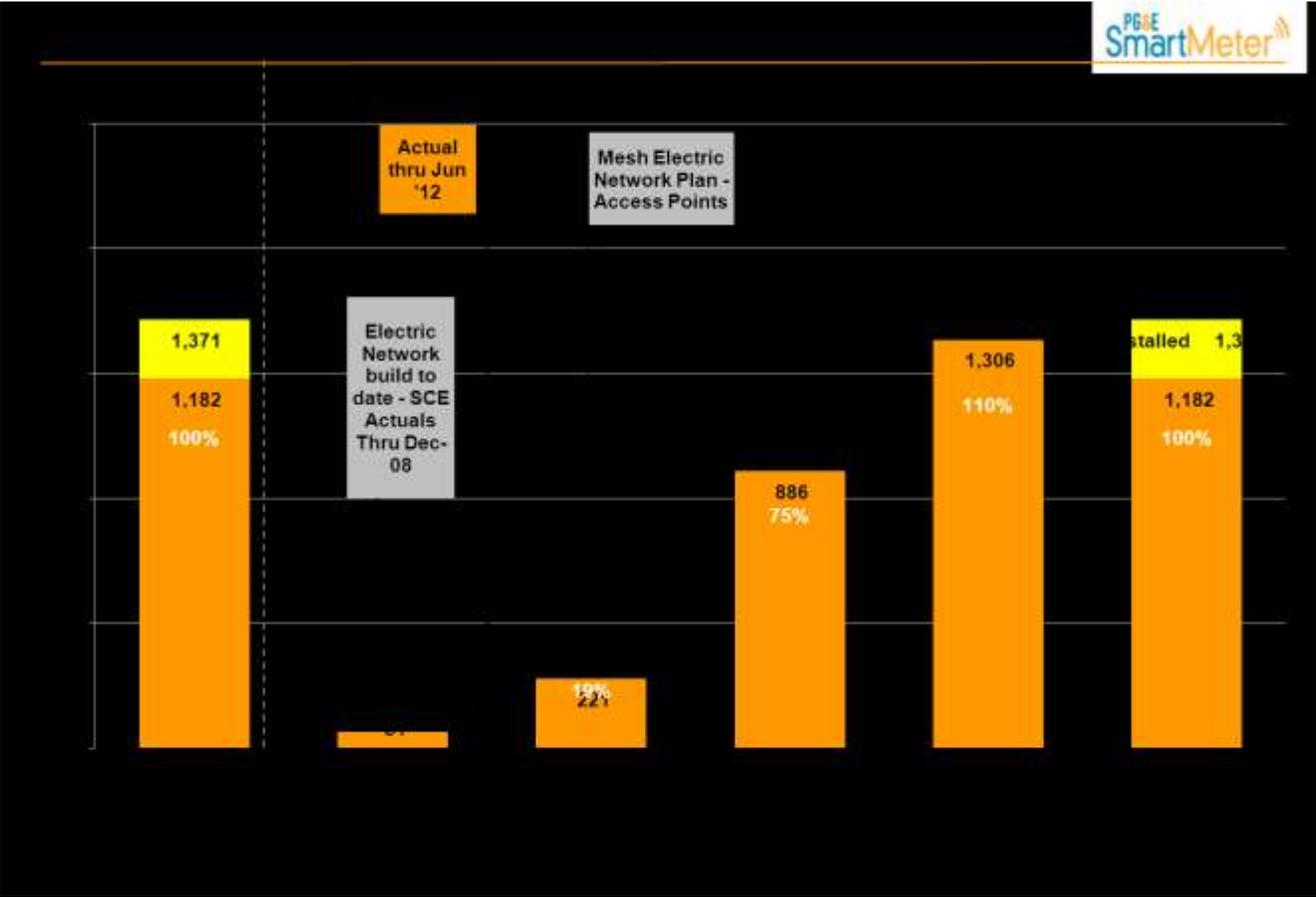
5 **Table II – 1**

Cumulative Meters (In Thousands)	2007	2008	2009	2010	2011	2012
Electric Meters Installed	136	376	2,306	4,067	5,095	5,260
Gas Meters Installed	142	1,294	2,310	3,645	4,149	4,265
Total	278	1,670	4,616	7,712	9,244	9,525
Electric Meters Activated	54	183	1,150	2,000	2,504	3,171
Gas Meters Activated	24	601	1,538	2,192	2,539	2,963
Total	78	784	2,688	4,192	5,043	6,134

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1 **Table II – 2**



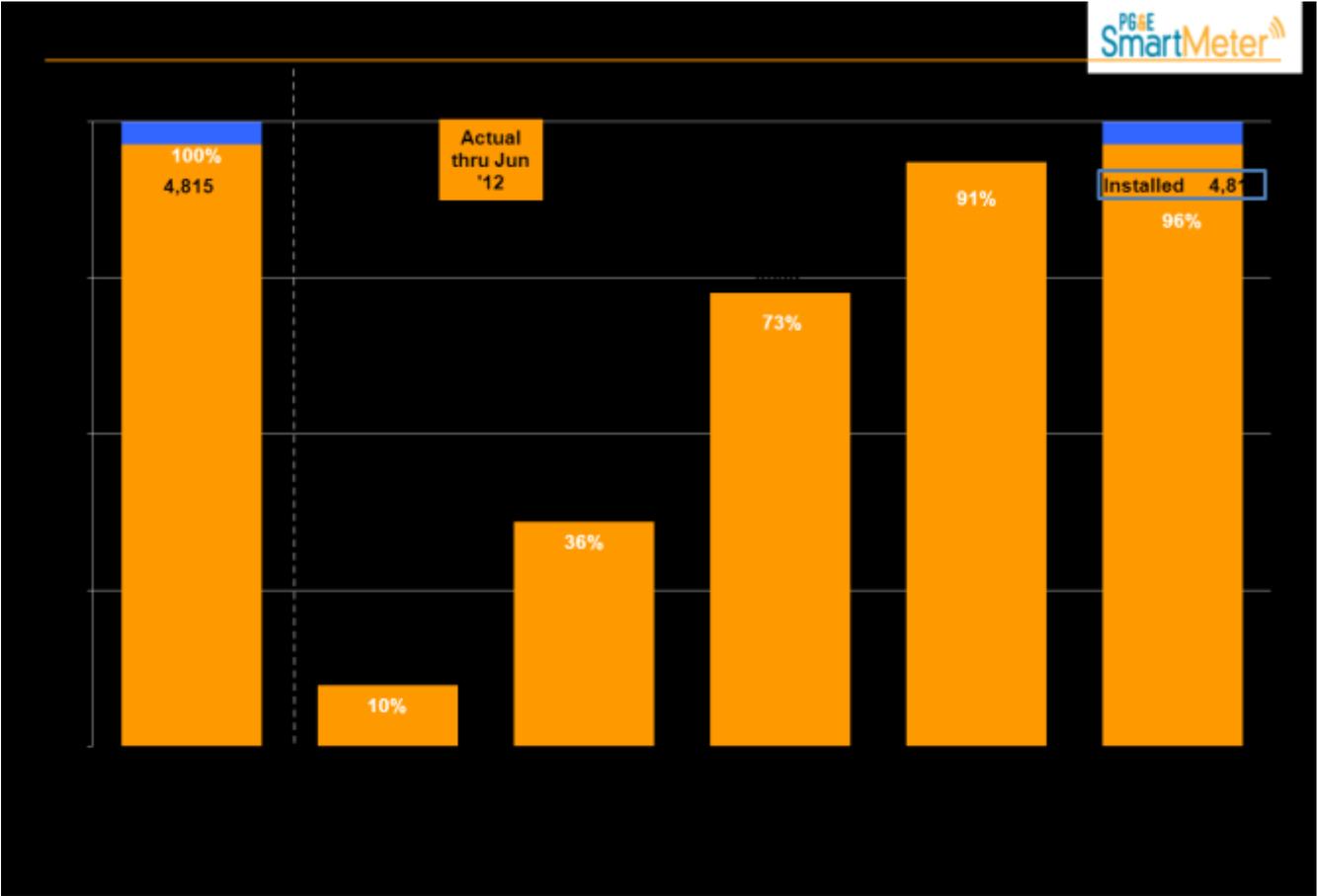
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<u>Electric Network - Substation SCE</u>	<u>Total</u>	<u>Yr 1 (to Dec-07)</u>				
Cumulative Installed thru 12/12 Plan	51	51				
	51	51				
<u>Electric Network - RF Mesh Access Points</u>	<u>Total</u>	<u>Yr 1 (to Dec-07)</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>
Cumulative Installed thru 12/12 Plan	1,371	-	221	886	1,306	1,371
	1,182	-	221	886	1,306	1,182

3

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1 **Table II – 3**



2

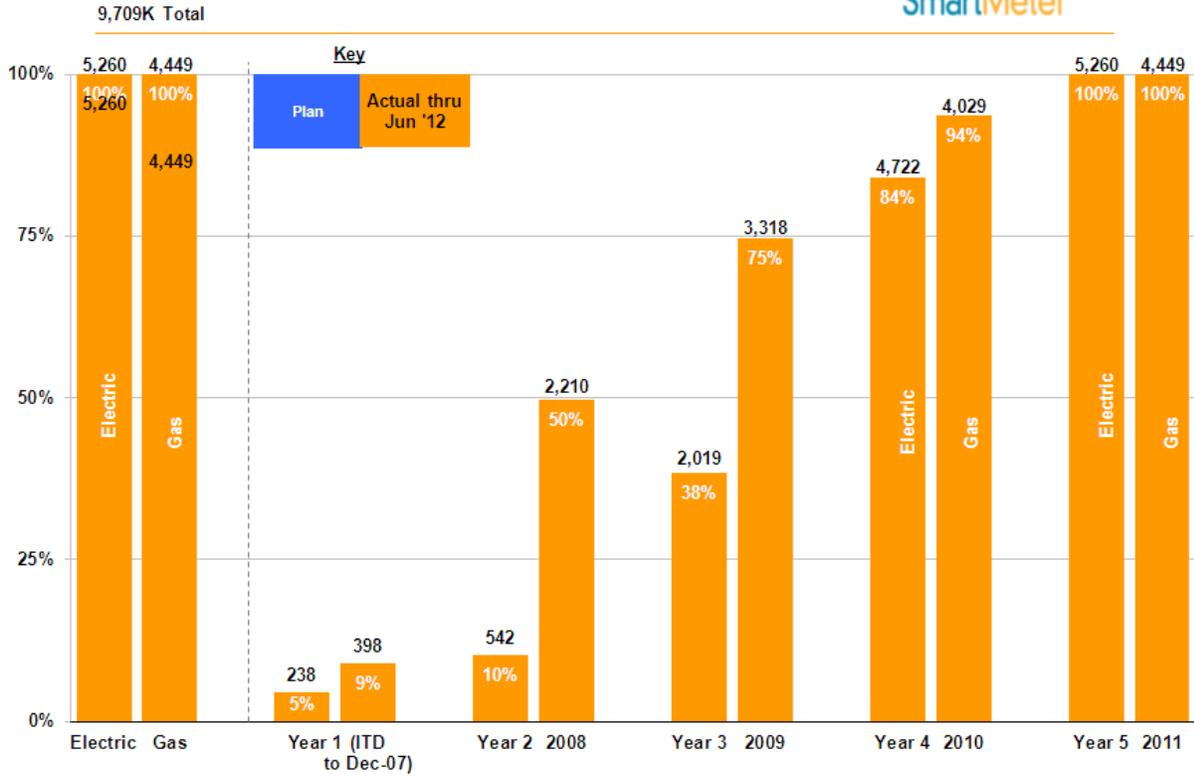
Cumulative Data Collection Unit (DCU) Installations	Total	Yr 1 (to Dec-07)	2008	2009	2010	2011
Installed thru 12/12	4,815	487	1,800	3,632	4,677	4,815
Plan	5,000	487	1,800	3,632	4,553	5,000

3

4

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 12/12	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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1 C. Information Technology

2 The SmartMeter™ Program established the SmartMeter™ Technology Completion
3 Project (SMTCP) in the spring of 2011 to consolidate its remaining individual
4 SmartMeter™ IT projects, including performance enhancement efforts, into a single
5 effort. Centralized project management of the remaining IT efforts resulted in a
6 focused, streamlined and financially-efficient solution delivery. The SMTCP Project was
7 successfully completed and all functionality was transitioned to Operational Support in
8 December 2011. The SmartMeter™ IT work is now substantially complete.⁷

9 **III. Program Costs and Benefits**

10 A. SmartMeter™ Program Costs

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

16 The Program budget includes a risk-based allowance directed by the officer-led
17 Steering Committee, which the CPUC authorized to address unanticipated costs
18 necessary to complete the defined Program work scope. In addition, the PMO
19 recommends reallocations, both increases and decreases, within and among
20 workstream budgets, as circumstances require.

21 As shown in Table III-1, through December 31, 2012, the SmartMeter™ Program
22 incurred costs of approximately \$2,293 million (\$1,862 million in capital and \$431 million
23 in expense). Of this total dollar amount, Field Delivery activities have cost

⁷ Work on the IT project related to the Peak Time Rebate (PTR) program has begun but is currently on hold until the CPUC approves the scope and timeline for the program. A decision on the PTR Program is pending in the 2010 Rate Design Window proceeding (Application 10-02-028).

1 approximately \$1,514 million (66 percent) and IT-related activities have cost
 2 approximately \$510 million (22 percent). The remaining 12 percent is attributed to the
 3 (a) Customer & SM Operations and (b) PMO/Business Operations categories.

4 **Table III – 1**

(\$ Millions)	Information Technology & Business Process					Risk-Based Allowance
	TOTAL	Field Delivery & Solutions	Customer & SM Operations	PMO & Technology Monitoring		
Plan as of June 30, 2012	2,335	1,540	493	198	105	
Cost Adjustments	(3)	-	(3)	-	-	
Plan as of December 31, 2012	2,332	1,540	490	198	105	
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, 2012	2,293	1,514	484	184	104	
% of Plan	98%	98%	99%	96%	99%	

5 Note: Totals subject to rounding

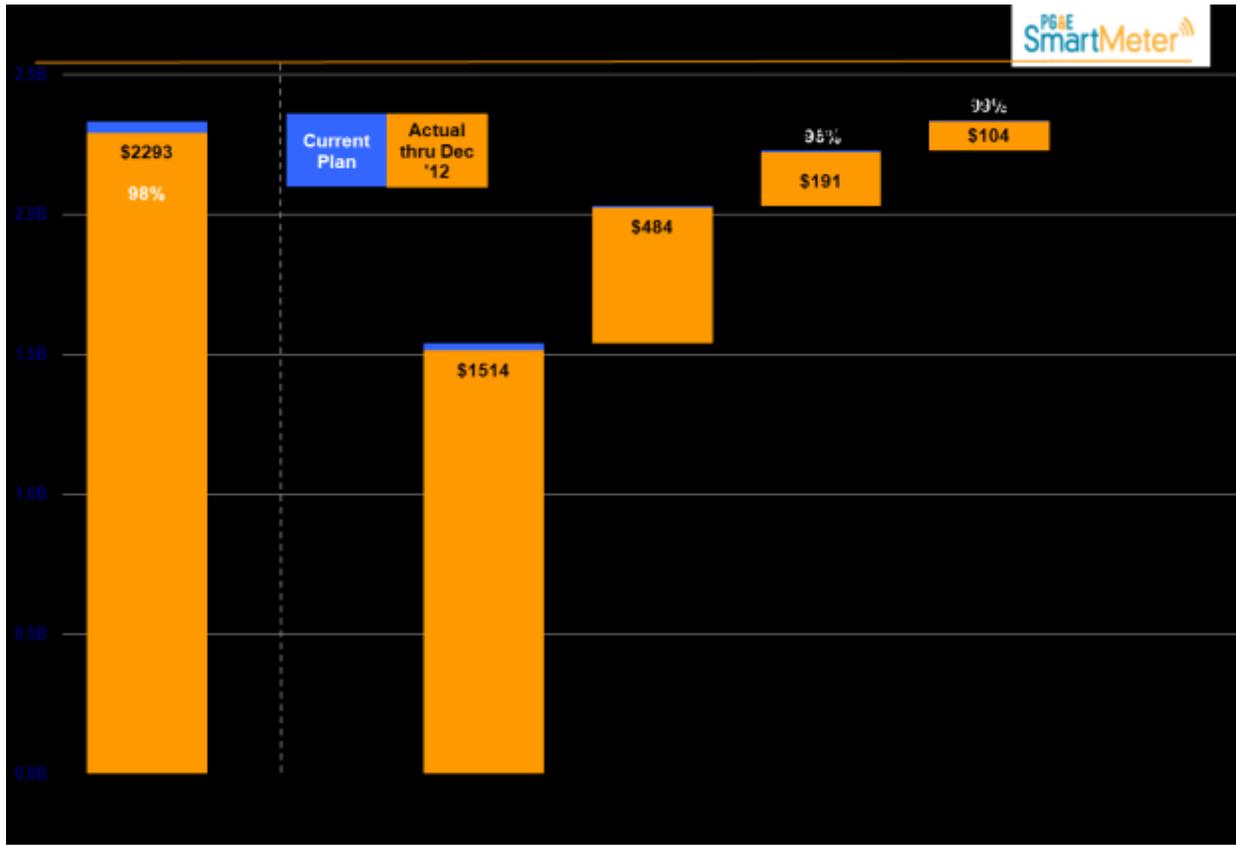
6 The Customer & SM Operations category includes \$54.8 million specifically
 7 authorized in the AMI Decision for the purpose of marketing Critical Peak Pricing
 8 programs. As of December 31, 2012, PG&E utilized approximately \$47.7 million of this
 9 \$54.8 million in support of SmartRate™ marketing.

(Thousands of Dollars)	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Total
SmartRate™ Marketing & Education and Customer Web Presentment	349	1,166	6,811	6,828	2,500	19,385	10,641	47,679

10
 11 Tables III-2 through III-7 show the SmartMeter™ Program costs PG&E has incurred
 12 from inception through December 31, 2012, in each major budget category. The percent-
 13 of-expenditures refers to the total incurred expenditure through December 31, 2012 as a
 14 percentage of the adjusted workstream budgets at Program completion.

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 16
 17
 18

1 **Table III-2**



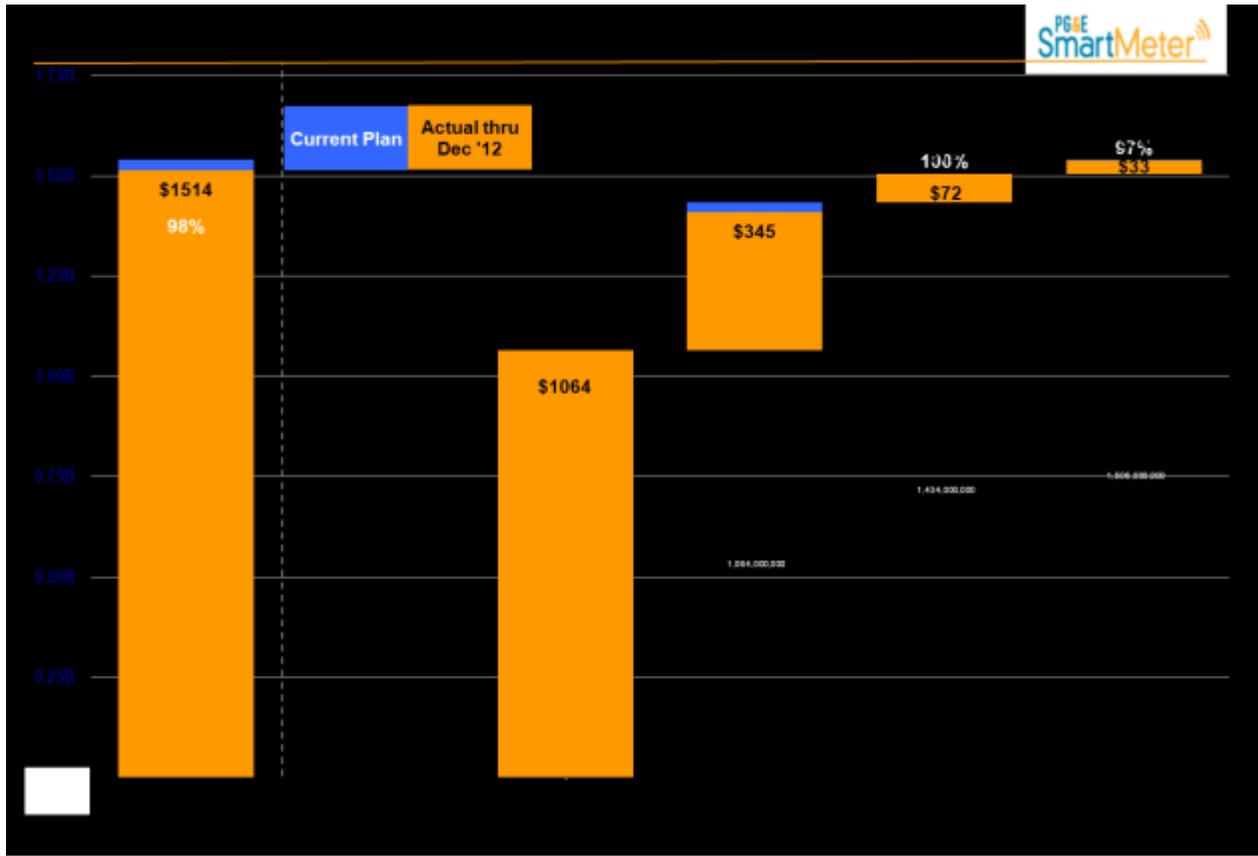
2

\$ Millions	Total SmartMeter Program Costs	Field Delivery	IT	Customer & SM Operations	PMO	Risk-Based Allowance
Actual thru December 31, 2012	\$ 2,293	1,514	484	191	104	N/A
Plan as of June 30, 2012	\$ 2,335	1,540	493	198	105	-
Cost Changes/Reallocation	\$ (3)	-	(3)	-	-	-
Plan as of December 31, 2012	\$ 2,332	1,540	490	198	105	-
% of Plan completed	98%	98%	99%	96%	99%	-

3 Note: Totals subject to rounding

4

1 **Table III-3**



2

\$ Millions	Total Field Delivery	Strategic Relationships	Endpoint Installation	Field Delivery Office	Network Installation
Actuals thru December 31, 2012	1,514	1,064	345	72	33
Plan as of June 30, 2012	1,540	1,064	370	72	34
Cost Changes/Reallocation	-	-	-	-	-
Plan as of December 31, 2012	1,540	1,064	370	72	34
% of Plan Expended	98%	100%	93%	100%	97%

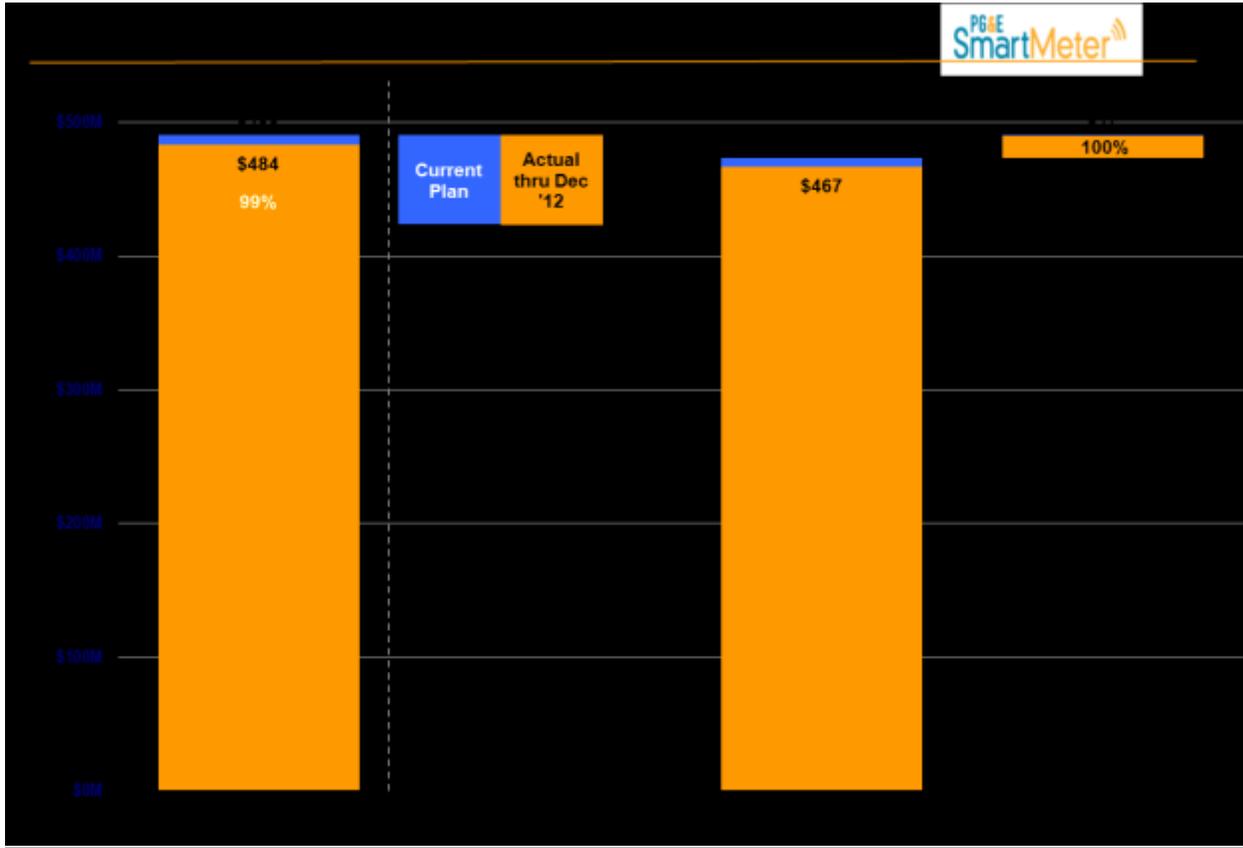
\$ Millions	Network Installation	Electric Network	Gas Network
Actuals thru December 31, 2012	\$ 33	21	12
Plan as of June 30, 2012	\$ 34	23	12
Cost Changes/Reallocation	\$ -	-	-
Plan as of December 31, 2012	\$ 34	23	12
% of Plan Expended	97%	91%	99%

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**



2

\$ Millions	Total Information and Technology	IT / CC&B	Business Process
Actuals thru December 31, 2012	\$ 484	467	17
Plan as of June 30, 2012	\$ 493	476	17
Cost Changes/Reallocation	\$ (3)	(3)	-
Plan as of December 31, 2012	\$ 490	473	17
% of Plan Expended	99%	99%	100%

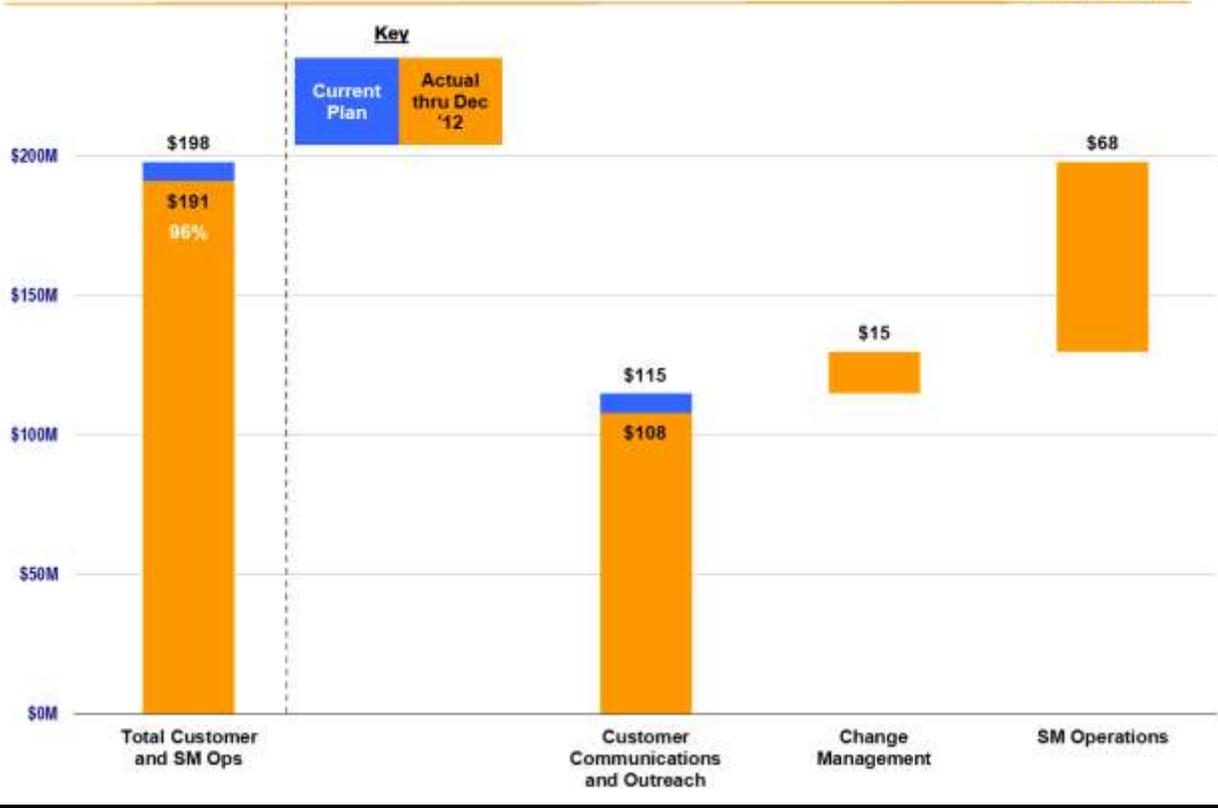
Note: Totals subject to rounding

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1 **Table III-5**

Customer and SM Operations Costs (\$ Millions)



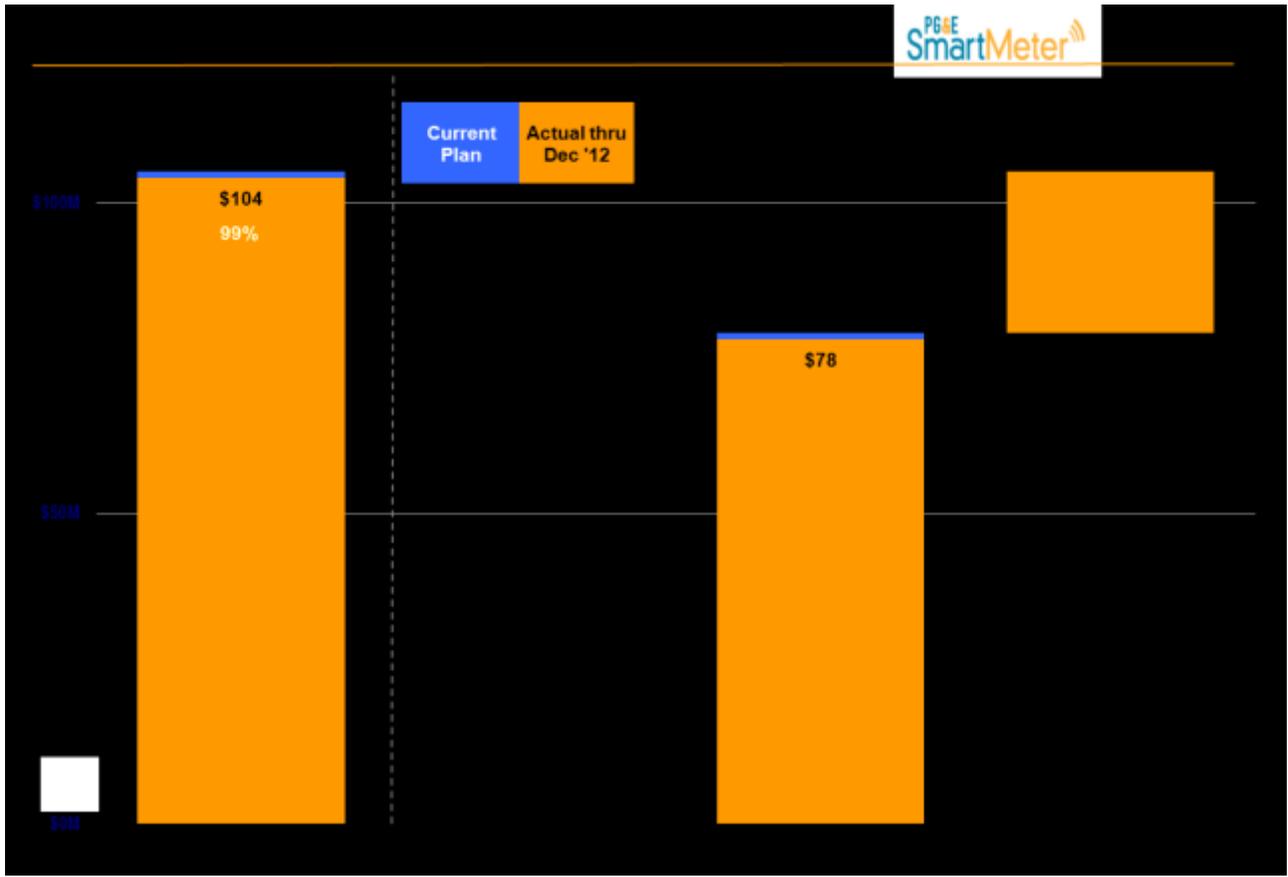
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\$ Millions	Total Customer and SM Ops	Customer Communications and Outreach	Change Management	SM Operations
Actuals thru December 31, 2012	\$ 191	108	15	68
Plan as of June 30, 2012	\$ 198	115	15	68
Cost Changes/Reallocation	\$ -	-	-	-
Plan as of December 31, 2012	\$ 198	115	15	68
% of Plan Expended	96%	94%	100%	100%

3 Note: Totals subject to rounding

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1 **Table III-6**



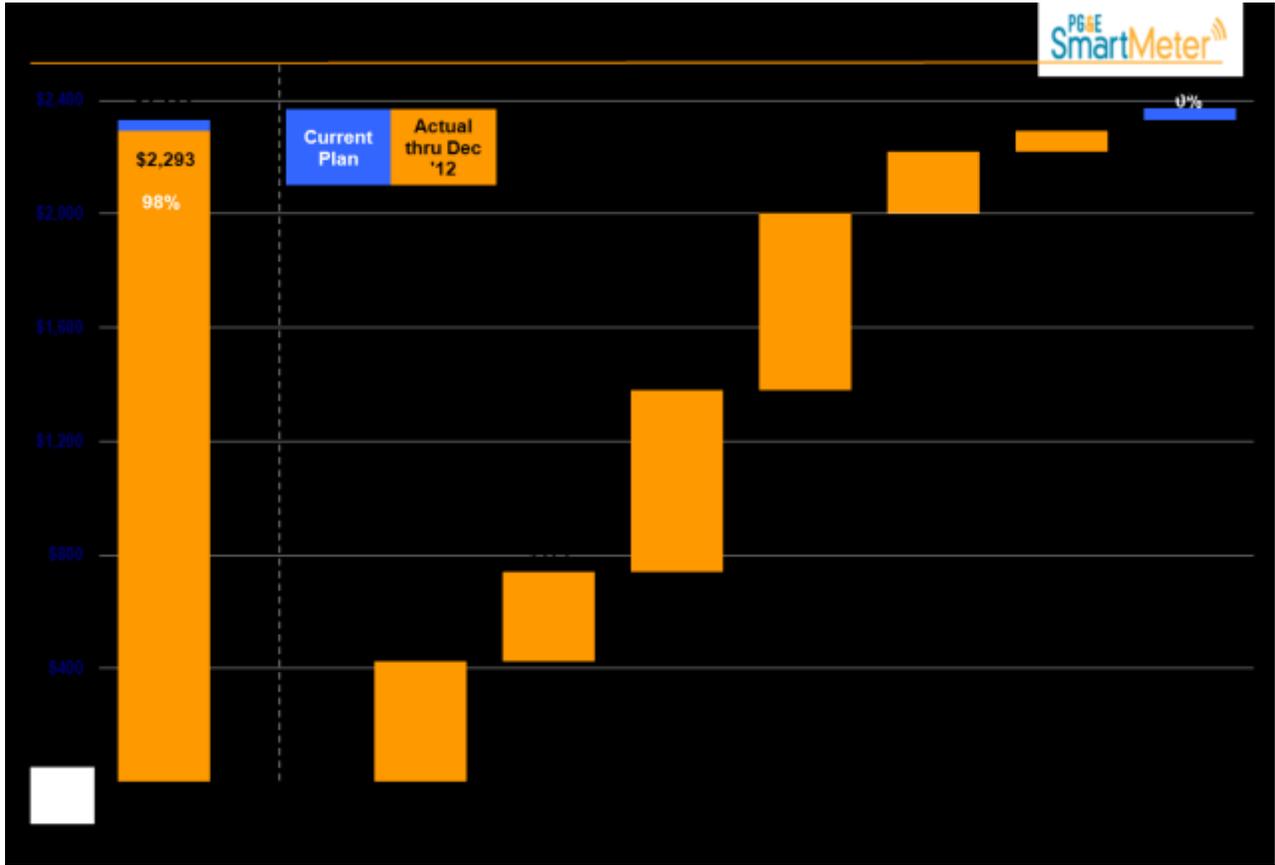
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\$ Millions	Total PMO and Technology Monitoring	PMO	Technology Monitoring
Actuals thru December 31, 2012	\$ 104	78	26
Plan as of June 30, 2012	\$ 105	79	26
Cost Changes/Reallocation	\$ -	-	-
Plan as of December 31, 2012	\$ 105	79	26
% of Plan Expended	99%	99%	100%

3 Note: Totals subject to rounding

4

1 **Table III-7**



2

\$ Millions	Project Costs	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
		(to Dec-07)	(CY 2008)	(CY 2009)	(CY 2010)	(CY 2011)	(CY 2012)	(CY 2013)
Actuals thru December 31, 2012	\$ 2,293	426	315	640	623	215	74	-
Plan as of December 31, 2012	\$ 2,332	426	315	640	623	215	74	39
% of Plan Expended	98%	100%	100%	100%	100%	100%	100%	0%

3 Note: Totals subject to rounding

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1 B. Operational Benefits Realization

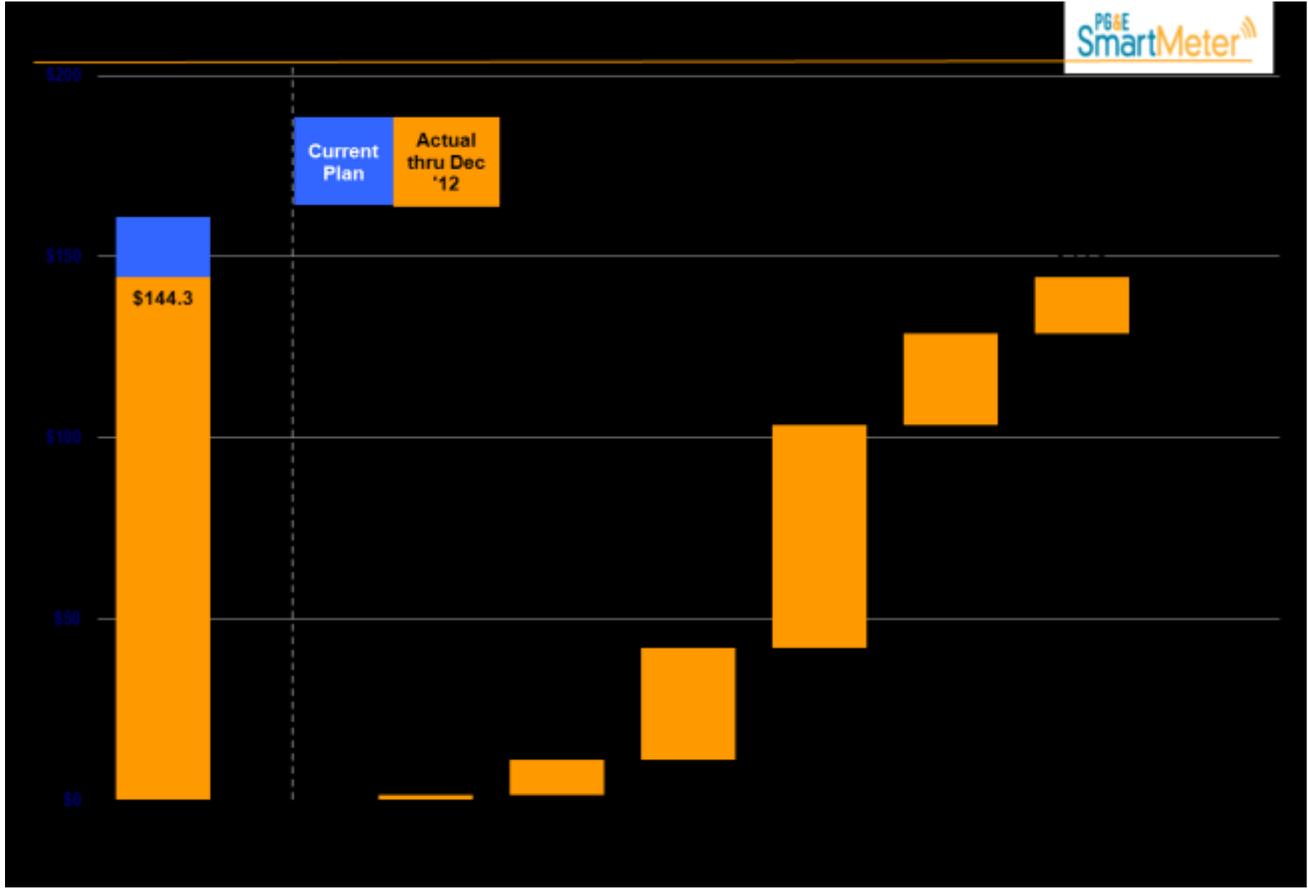
2 The Program realizes operational benefits when meters fitted with SmartMeter™
3 technology are activated, which occurs following installation of the meters and transition
4 to SmartMeter™-based wireless billing.

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

11 PG&E’s first meter activations occurred in December 2007. Through December 31,
12 2012, approximately 9,075,000 meters have been transitioned, and approximately
13 6,134,000 meters have been activated, with \$161.1 million corresponding cumulative
14 benefits recorded as credits to the balancing accounts. Such amounts are consistent
15 with the calculation methodologies and savings rates adopted in the AMI and Upgrade
16 Decisions, as adjusted by the 2011 General Rate Case (GRC) Decision 11-05-018.

17 Table III-8 shows activated meters and the corresponding benefits based on the
18 savings rates adopted in the AMI and Upgrade Decisions. These benefits totaled
19 \$1.9543 per meter per month for electric and \$1.0366 per meter per month for gas.
20 Commission-approval of the 2011 GRC Settlement set activated meter benefits at
21 \$0.9225 per meter per month for electric and \$0.0189 per meter per month for gas. In
22 compliance with the 2011 GRC Settlement, the activated meter benefits were adjusted
23 effective January 1, 2011, the largest adjustment of which was the removal of meter-
24 reading savings that are now reflected in a new Meter Reading Cost Balancing Account.

1 **Table III – 8**



2

Activated Meter Benefit - Current Forecast (As of December 31, 2012)							
		<u>Year 1*</u>	<u>Year 2*</u>	<u>Year 3*</u>	<u>Year 4</u>	<u>Year 5</u>	<u>Year 6</u>
(in thousands)		(To Dec-07)	(CY 2008)	(CY 2009)	(CY 2010)	(CY 2011)	(CY 2012)
Meters							
Activated Electric meter months		50	1,436	6,669	17,495	26,812	34,430
Activated Gas meter months		21	2,086	12,666	21,341	28,314	33,345
Total Activated meter months		71	3,521	19,335	38,836	55,127	67,775
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	\$31,762
Gas at \$0.02 per meter month		-	-	-	-	\$535	\$630
Reduced Software Licensing		\$1,251	\$5,000	\$5,000	\$5,000	-	-
Automate Interval Billing		-	-	-	-	-	-
		\$1,362	\$9,706	\$31,054	\$61,313	\$25,269	\$32,392

3 Note: Totals subject to rounding

4

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 in
 4 order to better characterize system performance.

5 In Table IV-1, PG&E has summarized SmartMeter™ Program Data metrics for
 6 timely and estimated bills for the third and fourth quarters of 2012.

7 **Table IV – 1**

Timely Bills			Estimated Bills		
Month	Overall	SmartMeter	Month	Overall	SmartMeter
July 12	99.93%	99.97%	July 12	0.27%	0.08%
August 12	99.93%	99.97%	August 12	0.26%	0.07%
September 12	99.92%	99.95%	September 12	0.23%	0.07%
October 12	99.93%	99.96%	October 12	0.25%	0.07%
November 12	99.90%	99.95%	November 12	0.23%	0.07%
December 12	99.89%	99.95%	December 12	0.33%	0.08%
Total % of Service Agreements (SAs) Billed ≤ 35 Days as compared to all active SAs.			Number of bill segment calculations based on estimated usage as a % of all completed bill segments.		

8

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

17 ///

18 ///

19 ///

20 ///

1 **Table IV – 2**

Performance Criteria	Jul'12 thru Dec'12	Jan'12 thru Jun'12	Jul'11 thru Dec'11	Jan'11 thru Jun'11	Jul'10 thru Dec'10	Jan'10 thru Jun'10
1. Electric module failure rate	0.43%	0.25%	0.27%	0.42%	0.45%	0.09%
2. Gas module failure rate	0.13%	0.02%	0.11%	0.27%	0.09%	0.14%
3. Electric network failure rate	0.31%	0.57%	0.19%	0.52%	0.35%	0.23%
4. Gas network failure rate	0.25%	0.45%	0.95%	0.65%	0.13%	0.14%
5. Electric billing data collection failure rate	0.18%	0.11%	0.15%	0.23%	0.27%	0.39%
6. Gas billing data collection failure rate	0.25%	0.39%	0.36%	0.29%	0.23%	0.16%

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.

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

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

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

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

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

22 PG&E launched its residential critical peak pricing program, SmartRate™, in May
23 2008. This program encourages customers to manage energy usage during particularly
24 hot summer days, when SmartDay™ events are triggered. PG&E's more aggressive

1 acquisition efforts in 2012 have resulted in 62,489 new customer enrollments in 2012;
2 as of December 31, 2012, PG&E's SmartRate™ program had a total of 79,633 active
3 and pending participants. And as of March 24, 2013, PG&E's SmartRate™ program
4 had a total of 82,264 active and pending participants.

5 On March 2, 2010, the Commission issued Decision 10-02-032 in PG&E's 2009
6 Rate Design Window proceeding. In that decision, the CPUC took a major step forward
7 in its policy to make dynamic pricing available for all electric customers. Specifically,
8 the CPUC's decision adopted default and optional critical peak pricing (CPP)
9 and time-of-use rates – known as Peak Day Pricing (PDP) rates – to be implemented
10 for certain PG&E customers beginning May 1, 2010. The decision also adopted
11 appropriate customer outreach and education activities and measures to ensure
12 customer awareness and understanding of the new rates and options. Given the
13 differences between SmartRate™ and PDP rates, as well as uncertainty in the ultimate
14 characteristics of the pending PDP program, PG&E adjusted the focus of its
15 SmartRate™ outreach to maintain its then-existing population of program participants.
16 SmartRate™ customers received both a welcome-back letter and retention mailer. The
17 welcome-back letter reminded customers about the start of the season and provided
18 information to allow customers to update their notification sources. The retention mailer
19 included customer-centric tips for event days. PG&E also communicated with
20 customers when notifications were unsuccessful to obtain updates to notification contact
21 information.

22 In June 2012, PG&E published its Final 2011 Ex Post and Ex Ante Load Impact
23 Evaluation report for the Residential SmartRate™, Time-Of-Use rates schedules and
24 SmartAC™ Program, which provided details on the 2011 season performance of the

1 SmartRate™ population⁸. These annual evaluations are conducted using the industry's
2 best practices and methods and are compliant with California's Demand Response
3 Protocols (CPUC Decision 08-04-050). The 2011 report's findings include:

- 4 ▪ There were 15 SmartDays™ during PG&E's 2011 season (conducted from
5 May 1 through October 31).
- 6 ▪ On average, participants reduced peak electricity use by 13 percent across the
7 15 event days.
- 8 ▪ June's two event days offered the season's highest average reduction of about
9 15 percent.
- 10 ▪ In general, participants with central air conditioning reduced peak electricity use
11 more (approximately 23 percent) than those without it.
- 12 ▪ 86 percent of SmartRate™ respondents report being very satisfied with
13 SmartRate™.
- 14 ▪ A higher portion of low-income customers indicated high levels of satisfaction
15 compared to non-low-income respondents (90 percent versus 83 percent).
- 16 ▪ 83 percent of respondents perceived they were saving energy during their
17 SmartRate™ participation and 82 percent of those thought they experienced a
18 lower bill.
- 19 ▪ 90 percent of respondents plan to continue on SmartRate™.
- 20 ▪ 88 percent of respondents would recommend SmartRate™ to a friend, and 60
21 percent have done so.

22 Although PG&E focused on retaining existing SmartRate™ customers in the 2010-
23 2011 period, it also attempted to recruit new customers in connection with the

8 The evaluation of 2012 performance will be filed with the Commission on April 1, 2013.

1 deployment of SmartMeters™ to improve demand response and customer satisfaction.
2 This new campaign solicited tips from participants concerning how to reduce peak
3 demand (and associated electric bills) by offering a chance to win a prize with their
4 submission. PG&E communicated these tips to customers through SmartDay™ event
5 notifications to timely encourage customers to respond to the price signals.

6 In November 2011, the CPUC granted PG&E's request to retain SmartRate™ as an
7 option for residential customers until the Commission completed its pending review of
8 default residential dynamic pricing rates in Application 10-08-005. In 2012, given the
9 greater certainty that the SmartRate™ program would continue, PG&E broadened its
10 customer acquisition efforts, designed to meet an aggressive target of increasing
11 SmartRate™ enrollment from about 22,000 to 77,000 total customers by the end of
12 2012. PG&E exceeded its 2012 target, having enrolled 79,633 customers in
13 SmartRate™ by the end of 2012.

14 During 2012, PG&E's SmartRate™ marketing plan leveraged the following lessons
15 learned from prior SmartRate™ marketing efforts:

- 16 ■ Targeted direct mail was selected as the primary marketing tactic due to its
17 proven effectiveness in driving program enrollment.
- 18 ■ Messaging used in the 2012 campaign utilized insights from customer responses
19 in 2009 and prior research on messaging to determine which approaches
20 resulted in the highest levels of customer responses.
- 21 ■ Cross-marketing was conducted with PG&E's SmartAC customers because
22 previous marketing efforts to these customers in 2009 had resulted in among the
23 highest levels of SmartRate™ enrollments

1 PG&E also expanded the reach of the campaign to include more eligible customers.
2 The larger audience of eligible residential customers was segmented and targeted
3 based on customer data including: higher levels of energy usage, geographic targeting
4 to warm climate zones, propensity to respond, and other factors. Additionally, the 2012
5 campaign included follow-up email marketing to customers who requested additional
6 information about SmartRate™ as a result of the 2011 lead generation efforts.

7 To support currently enrolled customers, the SmartRate™ customer strategy
8 provides ongoing communications to maximize their benefits from the program. These
9 customers receive a series of communications to inform and engage them on ways to
10 succeed on SmartDays. The intent of these efforts is to maintain the historically low
11 level of less than two percent attrition.

12 The combination of marketing efforts to both acquire and retain customers has, as
13 of March 24, 2013, resulted in a total of 82,264 active and pending SmartRate™
14 customers, surpassing PG&E's goal of 77,000 total customer enrollments by the end of
15 2012, while maintaining low attrition rates. PG&E plans to continue its SmartRate™
16 marketing efforts in 2013 by further leveraging lessons learned and best practices from
17 2012. PG&E's 2013 SmartRate™ marketing efforts will focus on three key areas: lead
18 generation, direct acquisition, and on-going customer communications enforcing the
19 program benefits. Through its 2013 marketing efforts, PG&E aims to achieve
20 SmartRate™ enrollments of at least 100,000 customers by the end of 2013.

21 **VI. Advances in AMI Technology**

22 **A. Distribution Automation Update**

23 On June 30, 2011, in compliance with Senate Bill 17, PG&E submitted its Smart Grid
24 Deployment Plan (Application 11-06-029) to the CPUC, sharing PG&E's vision for the

1 Smart Grid and a broad plan for modernizing its electric grid infrastructure to deliver a
2 host of energy and cost savings to customers. The plan included proposals by which
3 PG&E's AMI communications network would support Distribution Automation
4 applications, including line sensor applications.

5 On November 21, 2011, PG&E filed its Smart Grid Pilot Deployment Project,
6 Application 11-11-017, seeking approval for six pilot projects that will test, evaluate, and
7 pilot selected technologies and initiatives, which when fully deployed could provide
8 significant customer benefits, modernize PG&E's electric grid, and support the Smart
9 Grid policy goals outlined in Senate Bill 17. CPUC Decision 13-03-032 adopted four of
10 the six proposed projects.

11 In Decision 12-04-025, the Commission adopted metrics to measure the Smart Grid
12 deployments of PG&E, Southern California Edison Company, and San Diego Gas and
13 Electric Company. PG&E will report these metrics in its Smart Grid Deployment Plan
14 Annual Report, to be submitted to the Commission on October 1, 2012. As the
15 SmartMeter™ program draws to a close, PG&E expects that the Commission will
16 monitor PG&E's participation in and reporting on Distribution Automation activities in the
17 Smart Grid proceeding.

18 B. HAN Update

19 In March 2012, PG&E began its Home Area Network (HAN) Initial Rollout Phase,
20 providing in-home display devices to approximately 430 residential customers. PG&E
21 issued an initial survey and conducted focus groups with these pilot participants in 2012
22 and will conduct a final survey and focus group in April 2013.

23 In the latter half of 2012, PG&E completed planning and design for its Early Adopter
24 Phase, whereby customers will be able to buy and self-register a HAN device with

1 PG&E to obtain near-real-time energy usage data from their SmartMeter™. PG&E
2 launched the Early Adopter Phase on January 15, 2013, and plans to automate the
3 registration process through its MyEnergy portal in the second half of 2013.

4 On September 27, 2012, the Commission issued Resolution E-4527, addressing the
5 utilities' HAN Implementation Plans. These new requirements included:

- 6 ■ Accepting customers' HAN activation requests beginning on January 15, 2013;
7 and
- 8 ■ Supporting an infrastructure that can accommodate the following number of HAN
9 activation requests:
 - 10 ○ 5,000 before June 30, 2013;
 - 11 ○ 25,000 before December 31, 2013; and
 - 12 ○ 200,000 before December 31, 2014.

13 PG&E submitted its revised HAN Implementation Plan on October 29, 2012,
14 incorporating the new requirements provided in Resolution E-4527. In addition, PG&E
15 collaborated with the other California investor-owned electric utilities to develop a
16 proposed common set of HAN-related requirements. These included: 1) a common set
17 of reasonable requirements and a testing process for validating interoperability between
18 the utilities' electric smart meters and commercially-available HAN devices offered by
19 third parties, and 2) a common set of reasonable requirements to be satisfied by a HAN
20 device supplier for its device to be eligible for interoperability validation testing by the
21 utility. On behalf of the collaborating utilities, SCE filed these proposed requirements
22 with the Commission on December 3, 2012 in Advice Letter 2818-E, with a supplement
23 filed on March 25, 2013. The Advice Letter has not yet been approved.

1 C. Technology Industry Updates

2 PG&E continues to lead and participate in industry activities related to advanced
3 metering and communication networks, including through memberships in professional
4 organizations and attendance at conventions and trade shows. In the third quarter of
5 2012, PG&E representatives delivered presentations at the Autovation conference
6 (September 2012).

7 PG&E is committed to an open and interoperable Smart Grid and now reports on its
8 progress on the status of Smart Grid investments in its Smart Grid Annual Report, filed
9 in compliance with Ordering Paragraph 15 of CPUC Decision 10-06-047.