Rulemaking: 11-02-019
(U 39 E)
Exhibit No.: ______________
Date: November 4, 2011
Witnesses: Various

PACIFIC GAS AND ELECTRIC COMPANY

PIPELINE SAFETY ENHANCEMENT PLAN (IMPLEMENTATION PLAN)

ERRATA TO PREPARED TESTIMONY

DATED AUGUST 26, 2011

PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SAFETY ENHANCEMENT PLAN (IMPLEMENTATION PLAN), R.11-02-019
ERRATA TO PREPARED TESTIMONY
DATED AUGUST 26, 2011

Chapter 1: **Implementation Plan Policy**
Witness: **Thomas E. Bottorff**
Nikolas Stavropoulos

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
1-18	5		4.26	4.08
1-18	7		5.35	5.12
1-18	7		6.80	6.52
1-18	9		$1.93	$1.85
1-18	9		$47.16	$47.08
1-18	11		$14.95	$14.33
1-18	11		$294.75	$294.13
1-22	22		152	237
1-22	23		N/A	and gas maintenance and construction

PACIFIC GAS AND ELECTRIC COMPANY
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Chapter 3: **Gas Transmission Pipeline Modernization Program**
Witness: **Todd R. Hogenson**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
3-12	11		1971	1970
3-34	13		descending	ascending
3-49	23		non	highly

PACIFIC GAS AND ELECTRIC COMPANY
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Chapter 5: **Pipeline Records Integration Program**
Witness: **Steven A. Whelan**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
5-27	Table 5-5, Line 1	Forecast	$7.9	$11.6
5-27	Table 5-5, Line 2	Forecast	48.1	53.0
5-27	Table 5-5, Line 3	Forecast	34.7	37.6
5-27	Table 5-5, Line 4	Forecast	32.9	21.4

PACIFIC GAS AND ELECTRIC COMPANY
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Chapter 9: **Results of Operations**
Witness: **Nielson D. Jones**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
9-2	Table 9-2, Line 1	2012	$227,373	$197,971
9-2	Table 9-2, Line 1	2013	192,223	180,049
9-2	Table 9-2, Line 1	2014	274,267	233,407
9-2	Table 9-2, Line 1	Total	$693,863	611,427
9-2	Table 9-2, Line 2	2012	18,925	44,827
9-2	Table 9-2, Line 2	2013	28,610	36,978
9-2	Table 9-2, Line 2	2014	25,486	58,408
9-2	Table 9-2, Line 2	Total	73,021	140,213
9-2	Table 9-2, Line 3	2012	981	4,481
9-2	Table 9-2, Line 3	2013	-	3,806
9-2	Table 9-2, Line 3	2014	888	8,826
9-2	Table 9-2, Line 3	Total	1,869	17,113

PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SAFETY ENHANCEMENT PLAN (IMPLEMENTATION PLAN), R.11-02-019
ERRATA TO PREPARED TESTIMONY
DATED AUGUST 26, 2011

Chapter 10: **Cost Allocation and Rates**
Witness: **Ray E. Blatter**

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
10-6	Table 10-2, Line 1	2012	$0.05211	$0.04994
10-6	Table 10-2, Line 1	2013	$0.04501	$0.04439
10-6	Table 10-2, Line 1	2014	$0.06223	$0.05964
10-6	Table 10-2, Line 2	2012	$0.02494	$0.02547
10-6	Table 10-2, Line 2	2013	$0.02266	$0.02276
10-6	Table 10-2, Line 2	2014	$0.03157	$0.03184
10-6	Table 10-2, Line 3	2012	$0.00213	$0.00569
10-6	Table 10-2, Line 3	2013	$0.00369	$0.00480
10-6	Table 10-2, Line 3	2014	$0.00318	$0.00808
10-7	Table 10-3, Line 2	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$1.275	$1.272
10-7	Table 10-3, Line 2	Percentage Change	4.3%	4.1%
10-7	Table 10-3, Line 3	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$1.027	$1.025
10-7	Table 10-3, Line 3	Percentage Change	5.3%	5.1%
10-7	Table 10-3, Line 4	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.818	$0.816
10-7	Table 10-3, Line 4	Percentage Change	6.8%	6.5%

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
10-7	Table 10-3, Line 5	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.713	$0.711
10-7	Table 10-3, Line 5	Percentage Change	7.9%	7.6%
10-7	Table 10-3, Line 6	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$1.965	$1.962
10-7	Table 10-3, Line 6	Percentage Change	2.7%	2.6%
10-7	Table 10-3, Line 8	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.702	$0.700
10-7	Table 10-3, Line 8	Percentage Change	8.0%	7.7%
10-7	Table 10-3, Line 9	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.470	$0.468
10-7	Table 10-3, Line 9	Percentage Change	12.5%	11.9
10-7	Table 10-3, Line 10	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.300	$0.298
10-7	Table 10-3, Line 10	Percentage Change	21.0%	20.1%
10-7	Table 10-3, Line 12	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.196	$0.197
10-7	Table 10-3, Line 12	Percentage Change	14.6%	14.9%
10-7	Table 10-3, Line 13	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.094	$0.095
10-7	Table 10-3, Line 13	Percentage Change	36.0%	36.7%

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
10-7	Table 10-3, Line 14	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.044	$0.048
10-7	Table 10-3, Line 14	Percentage Change	5.0%	13.5%
10-7	Table 10-3, Line 15	Percentage Change	86.0%	87.8%
10-7	Table 10-3, Line 16	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.010	$0.013
10-7	Table 10-3, Line 16	Percentage Change	28.6%	76.4%
10-7	Table 10-3, Line 17	Percentage Change	16.1%	16.5%
10-7	Table 10-3, Line 18	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.080	$0.081
10-7	Table 10-3, Line 18	Percentage Change	45.2%	46.2%
10-7	Table 10-3, Line 20	Percentage Change	97.1%	99.1%
10-7	Table 10-3, Line 21	Percentage Change	96.8%	98.8%
10-7	Table 10-3, Line 22	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.052	$0.053
10-7	Table 10-3, Line 22	Percentage Change	90.9%	92.9
10-7	Table 10-3, Line 23	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.050	$0.051
10-7	Table 10-3, Line 23	Percentage Change	98.6%	100.7%
10-7	Table 10-3, Line 24	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.125	$0.126
10-7	Table 10-3,	Percentage	24.9%	25.4%

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
	Line 24	Change		
10-7	Table 10-3, Line 25	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	$0.148	$0.149
10-7	Table 10-3, Line 25	Percentage Change	20.2%	20.6%
10-7	Table 10-3, Line 26	Percentage Change	96.0%	98.0%
10-9	Table 10-4, Line 2	Percentage Change	3.6%	3.7%
10-9	Table 10-4, Line 3	Proposed 2012 Rates(a)(b) With Implementation Plan Costs ($/th)	$0.612	$0.613
10-9	Table 10-4, Line 3	Percentage Change	4.2%	4.3%
10-9	Table 10-4, Line 4	Proposed 2012 Rates(a)(b) With Implementation Plan Costs ($/th)	$0.562	$0.566
10-9	Table 10-4, Line 4	Percentage Change	0.4%	1.0%
10-9	Table 10-4, Line 5	Percentage Change	4.6%	4.7%
10-9	Table 10-4, Line 6	Proposed 2012 Rates(a)(b) With Implementation Plan Costs ($/th)	$0.527	$0.531
10-9	Table 10-4, Line 6	Percentage Change	0.4%	1.1%
10-9	Table 10-4, Line 7	Percentage Change	3.7%	3.8%
10-9	Table 10-4, Line 10	Percentage Change	4.6%	4.7%
10-9	Table 10-4, Line 11	Percentage Change	4.6%	4.7%
10-9	Table 10-4, Line 12	Proposed 2012 Rates(a)(b) With Implementation Plan Costs ($/th)	$0.570	$0.571
10-9	Table 10-4, Line 12	Percentage Change	4.6%	4.7%
10-9	Table 10-4,	Proposed 2012	$0.568	$0.569

Page(s)	Line(s)	Column(s)	Delete	Replace With/Insert
	Line 13	Rates(a)(b) With Implementation Plan Costs ($/th)		
10-9	Table 10-4, Line 13	Percentage Change	4.6%	4.7%
10-9	Table 10-4, Line 14	Percentage Change	4.0%	4.1%
10-9	Table 10-4, Line 15	Proposed 2012 Rates(a)(b) With Implementation Plan Costs ($/th)	$0.666	$0.667
10-9	Table 10-4, Line 15	Percentage Change	3.9%	4.0%
10-9	Table 10-4, Line 16	Percentage Change	4.6%	4.7%

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REPLACEMENT PAGES

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monthly bill for natural gas service. The cost of the pipeline system needed to transport and deliver the gas to customers is a small part of their gas bill.

Under PG&E's proposal, rates for bundled residential gas customers (customers who receive gas distribution and natural gas procurement services from PG&E) will increase in 2012 by ~~4.26~~ 4.08 percent, and bundled small and large commercial gas rates will increase by ~~5.35~~ 5.12 percent and ~~6.80~~ 6.52 percent, respectively. A typical residential customer using 37 therms per month will see an average monthly bill increase of $~~1.93~~1.85, from $45.23 to $~~47.16~~47.08. A typical small business customer using 287 therms per month would see an average monthly bill increase of $~~14.95~~14.33, from $279.80 to $~~294.75~~294.13.

4. Ratemaking Approach

In the Implementation Plan, PG&E has proposed a number of ratemaking mechanisms and procedures to increase PG&E's accountability to the public and the Commission.

First, PG&E has proposed a forecast for capital and expense for Phase 1. This forecast would be binding on PG&E for the four-year period, unless the Commission authorizes a modification to the budget. Under this approach, if circumstances lead to a change in Phase 1 project scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense or capital, PG&E would be required to submit an advice letter to the CPUC requesting a change in the project forecast. The public and interested parties would have an opportunity to comment on such a request. If the Commission decides not to modify the forecast in response to a request, PG&E would be required to manage and prioritize the remaining work scope within the approved forecast, potentially resulting in a shift of some projects to Phase 2 of the program.

Second, PG&E proposes to establish a balancing account to track expenditures and hold PG&E accountable to its plan. For capital expenditures, PG&E proposes to recover capital costs of a project in rates only after that project has been placed into operation and the actual costs of the project are known. Under this approach, PG&E would track the revenue requirements associated with capital expenditures after their project testing, approximately one-half mile of pipeline replacements and installation of 29 automated valves on the San Francisco Peninsula.

PG&E has reached out to customers and the community to improve communication and provide information about the natural gas transmission system. PG&E has created a new web page that provides gas system and safety information; now anyone can enter an address into the website to see if there is a transmission pipeline located nearby. PG&E also mailed more than two million letters to homes and businesses within 2,000 feet of a gas transmission line providing information about the proximity of gas transmission pipelines and additional safety information and resources. PG&E has held over 100 meetings with cities, counties and public groups to discuss gas safety issues and open lines of communication.

The IRP Report issued on June 8, 2011, raised a number of well-founded concerns about the way PG&E has managed its gas operations. It is clear from the report that PG&E needs to make major improvements in both its operations and culture. As recommended in the IRP Report, PG&E is in the process of establishing a new stand-alone gas operations organization. The new organizational structure will be announced shortly. As part of this process, PG&E is reexamining and retooling its entire organization, including its procedures, staffing, budget, and work priorities. PG&E will look to the top performers in the industry to benchmark best practices and evaluate PG&E's performance. In the past year, PG&E has hired ~~152~~237 new gas engineering and operations and gas maintenance and construction staff and it is in the process of recruiting more new employees.

The Implementation Plan is an important part of PG&E's overall strategy to enhance safety and improve operations. The program works in combination with and complements our existing pipeline replacement and maintenance programs, Risk Management Program and TIMP and Distribution Integrity Management Program, all of which are already funded in rates under the GT&S rate case settlement (Gas Accord V, adopted by D.11-04-031) and the 2011 General Rate Case Settlement (adopted by D.11-05-018). These work streams are part of our coordinated Gas Operations strategy and plan to achieve world-class standards of safety and performance. Our goal is, by our actions, to regain the trust of the public that PG&E puts safety first.

using the manufacturing techniques available at the time. Generally, pipe manufactured today is considered a higher quality product than pipe manufactured 50 to 70 years ago.

The 1970 threshold date was selected to reflect improvements in several areas:

(a) Changes in pipe metallurgy, plate welding to form pipe (longitudinal welds), the increase of pipe mill test pressures and other pipe inspection criteria combined to minimize the threats associated with imperfections introduced in the pipe manufacturing process.

(b) Publication in ~~1971~~1970 of federal natural gas transportation pipeline safety regulations, 49 CFR Part 192. These regulations established minimum pipeline manufacturing, design, construction, testing, and maintenance and operation safety standards for all pipeline operators that further distinguish the pipe on either side of this date.

(c) The manufacturing threat is considered present in pre-1970 vintages of pipe with a manufactured long seam by low-frequency Electric Resistance Weld (ERW), spiral weld, Single Submerged Arc Weld (SSAW), A.O. Smith flash weld, lap weld, hammer weld, or any pipe with a longitudinal joint efficiency factor[7] less than one.

To reduce system susceptibility to this threat, the Decision Tree prescribes pipe replacement for pipeline segments that have not been strength tested to 49 CFR 192, Subpart J requirements, operate at a SMYS equal to or greater than 30 percent, and are located within urban populated areas. Pipeline segments operating below 30 percent SMYS, but within urban populated areas, are

[7] A longitudinal joint efficiency factor is the ratio of the strength of the pipe long seam joint, to the strength of the base metal of the pipe. A longitudinal joint efficiency factor of 1.0 indicates the strength of the long seam joint is equal or greater to the base metal of the pipe. A joint efficiency factor of less than 1.0 indicates the strength of the long seam joint is less than the base metal of the pipe, and thus the weak link in the pipeline system. Refer to Attachment 3B, Implementation Plan Decision Point Justification for further description and pipe tables for Longitudinal Joint Efficiency Factors.

- Second – Decreasing PIR (highest to lowest), broken out into four Tier Groups, top 25 percent of PIR work started first, second set of 25 percent of PIR work started second, etc.
- Third – Percentage of HCA pipe (HCA footage/total footage) within each project from highest to lowest.

This prioritization system will serve as the basis for developing an annual project schedule, but will change based on the schedule impacts discussed in the next section.

b. Scheduling

PG&E expects to complete approximately 350 unique projects during Phase 1. PG&E will consider the following when scheduling and executing Phase 1 projects:

(1) PG&E will schedule those projects in order of ~~descending~~ascending margin of safety for the pipeline, considering interim safety enhancement measures and normal operating conditions, to ensure that public safety is the primary driver for schedule. PG&E will evaluate the interactive nature of the threats. While a single threat category may not pose a significant threat to the pipeline system, multiple threat categories on the same pipeline segment can contribute to a compounding effect, which may elevate the priority of any remedial measures.

(2) PG&E will schedule those projects that have a significant safety component in re-establishing operating pressures where pressure reductions would require curtailments of critical gas service.

(3) PG&E will schedule those projects with little or no expected permitting restrictions or delays. Conversely, for those projects with significant permitting challenges (e.g., endangered species and habitat), PG&E will begin engineering and permitting activities early in the Pipeline Program, since permitting on some pipe segments make take up to 18 to 30 months before construction can begin.

(4) PG&E will make reasonable efforts to schedule and sequence work in order to maintain customer service and minimize customer impact (outages).

estimate, PG&E has not included costs for any Supervisory Control and Data Acquisition or telecommunication work or repair. In addition, PG&E has added an allowance for replacing pipeline blow down stacks, line branch connections, and other existing line taps to each project.

(3) Indirect Costs

(a) Engineering, Design and Survey

Engineering, design, and surveying costs have been included at three percent of the material and construction costs, based on PG&E experience.

(b) Land and Right-of-Way

An allowance for ROW damages has been included based on land use. An allowance of 11 percent of the total estimated construction and material costs has been included in the non-congested areas to cover new ROW acquisitions (as necessary), ROW services, construction easements, and environmental mitigations. An allowance of 16 percent of the total estimated construction and material costs has been included in the semi-congested areas to cover new ROW acquisitions (as necessary), ROW services, construction easements, and environmental mitigation. An allowance of 6 percent of the total estimated construction and material costs has been included in the ~~non~~highly-congested areas to cover ROW services, construction easements, and environmental mitigations.

(c) Regulatory and Environmental Permitting

Regulatory and environmental permitting and service costs have been included at three percent of the material and construction costs, based on PG&E experience.

(d) Construction Management (Including Third-Party Inspection)

Construction management, construction inspection services, and quality control costs have been included at five percent of the material and construction costs.

The forecast summary by year and activity is summarized in Table 5-4 below.

TABLE 5-4
PACIFIC GAS AND ELECTRIC COMPANY
GTAM PROJECT FORECAST
($ IN MILLIONS)

Line No.		2011(a)	2012	2013	2014	Total
1	Capital	$7.4	$42.3	$27.2	$25.7	$102.6
2	Expense	0.5	5.8	7.5	7.2	21.0
3	Total	$7.9	$48.1	$34.7	$32.9	$123.6

(a) The 2011 expenses and capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011 will be funded by shareholders, as described in Chapter 8.

Table 5-5 below depicts the GTAM forecasts by phase.

TABLE 5-5
PACIFIC GAS AND ELECTRIC COMPANY
GTAM ASSUMPTIONS BY PHASE
($ IN MILLIONS)

Line No.	Phase	Forecast
1	Phase 0	$~~7.9~~11.6
2	Phase 1	~~48.1~~53.0
3	Phase 2	~~34.7~~37.6
4	Phase 3	~~32.9~~21.4
5	Total	$123.6

a. Assumptions

In general, the cost forecast for the GTAM Project assumes labor rates that are a blend of PG&E employees and third-party contractors. Process improvement and change management costs are assumed to be approximately 14 percent of the total forecast.

TABLE 9-1
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT REQUEST
($ IN THOUSANDS)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	Capital-Only Revenue Requirement	–	$13,205	$63,981	$154,816	$232,002
2	Expense-Only Revenue Requirement	–	234,074	156,852	145,825	536,751
3	Total	–	$247,279	$220,833	$300,641	$768,753

Table 9-2 shows the requested base revenue requirements, broken down by gas department lines of business, for the years 2012, 2013 and 2014.

TABLE 9-2
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT
($ IN THOUSANDS)

Line No.	Gas Department Lines of Business	2011	2012	2013	2014	Total
1	GT – Local Transmission	–	$~~227,373~~ 197,971	$~~192,223~~ 180,049	$~~274,267~~ 233,407	$~~693,863~~ 611,427
2	GT – Backbone Transmission	–	~~18,925~~ 44,827	~~28,610~~ 36,978	~~25,486~~ 58,408	~~73,021~~ 140,213
3	GS – Storage	–	~~981~~ 4,481	~~–~~ 3,806	~~888~~ 8,826	~~1,869~~ 17,113
4	Total	–	$247,279	$220,833	$300,641	$768,753

B. Cost Structure

PG&E's Gas Transmission and Storage (GT&S) rates currently in effect are based on the Gas Accord V Settlement, approved by the California Public Utilities Commission (CPUC or Commission) on April 14, 2011 in Decision 11-04-031. PG&E generally has maintained the same cost structure in this Implementation Plan.

C. Operations and Maintenance Expenses

The Operations and Maintenance (O&M) expense estimates for 2011 through 2014 include labor, materials, supplies, contracts, and other expenses related to implementing the Implementation Plan. Chapters 3 through 7 provide the estimated amount of these expenses and describe the services provided.

revenue requirements for capital projects and expenses are not included in rates.

TABLE 10-2
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED GAS PIPELINE SAFETY RATES
($ PER THERM)

Line No.		2012	2013	2014
1	Core	$~~0.05211~~ 0.04994	$~~0.04501~~ 0.04439	$~~0.06223~~ 0.05964
2	Noncore – Local Transmission/Distribution Level	$~~0.02494~~ 0.02547	$~~0.02266~~ 0.02276	$~~0.03157~~ 0.03184
3	Noncore – Backbone Transmission Level	$~~0.00213~~ 0.00569	$~~0.00369~~ 0.00480	$~~0.00318~~ 0.00808

D. Illustrative Gas Rate Impact Summary

Illustrative present (2011) and proposed annual average 2012 rates are summarized in Table 10-3 below. Illustrative bundled present core rates are based on gas transportation rates filed in PG&E's 2011 GRC decision (D.11-05-018) implementation core Advice 3206-G, effective June 1, 2011. Present noncore and wholesale rates are based on those filed in PG&E's 2011 GRC implementation noncore Advice 3207-G, effective June 1, 2011.

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TABLE 10-3
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE CLASS AVERAGE PRESENT AND PROPOSED RATES
($ PER THERM)

Line No.	Customer Class	Present June 2011 Rate(a) ($/th)	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	Percentage Change
1	Core Retail – Bundled(b)			
2	Residential (Non-CARE)(c)(e)	$1.223	$~~1.275~~1.272	~~4.3~~4.1%
3	Commercial, Small (Non-CARE)(e)	$0.975	$~~1.027~~1.025	~~5.3~~5.1%
4	Commercial, Large	$0.766	$~~0.818~~0.816	~~6.8~~6.5%
5	NGV Service – Compression on Customer Premises	$0.661	$~~0.713~~0.711	~~7.9~~7.6%
6	Compressed NGV Service	$1.912	$~~1.965~~1.962	~~2.7~~2.6%
7	Core Retail – Transportation Only(d)			
8	Residential	$0.650	$~~0.702~~0.700	~~8.0~~7.7%
9	Commercial, Small	$0.418	$~~0.470~~0.468	~~12.5~~11.9%
10	Commercial, Large	$0.248	$~~0.300~~0.298	~~21.0~~20.1%
11	Noncore – Transportation Only(d)			
12	Industrial Distribution	$0.171	$~~0.196~~0.197	~~14.6~~14.9%
13	Industrial Transmission	$0.069	$~~0.094~~0.095	~~36.0~~36.7%
14	Industrial Backbone	$0.042	$~~0.044~~0.048	~~5.0~~13.5%
15	Electric Generation – Distribution/Transmission	$0.029	$0.054	~~86.0~~87.8%
16	Electric Generation – Backbone	$0.007	$~~0.010~~0.013	~~28.6~~76.4%
17	Noncore NGV Service – Distribution	$0.155	$0.180	~~16.1~~16.5%
18	Noncore NGV Service – Transmission	$0.055	$~~0.080~~0.081	~~45.2~~46.2%
19	Wholesale – Transportation Only(d)			
20	Alpine Natural	$0.026	$0.051	~~97.1~~99.1%
21	Coalinga	$0.026	$0.051	~~96.8~~98.8%
22	Island Energy	$0.027	$~~0.052~~0.053	~~90.9~~92.9%
23	Palo Alto	$0.025	$~~0.050~~0.051	~~98.6~~100.7%
24	West Coast Gas – Castle(f)	$0.100	$~~0.125~~0.126	~~24.9~~25.4%
25	West Coast Gas – Mather Distribution(f)	$0.123	$~~0.148~~0.149	~~20.2~~20.6%
26	West Coast Gas – Mather Transmission	$0.026	$0.051	~~96.0~~98.0%

(a) Rates represent class average. Actual transportation rates will vary depending on the customer's load factor and seasonal usage. Rates are rounded to three decimal places for ease of viewing. Percentage rate changes are calculated on a 5-digit basis.

(b) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.429 per therm; (ii) a transportation component that recovers Customer Class Charge (CCC), customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a G-PPP surcharge that recovers the costs of low-income California Alternate Rates for Energy (CARE), Low Income Energy Efficiency (LIEE), Customer Energy Efficiency (CEE), Research Development and Demonstration program and State Board of Equalization (BOE)/CPUC Administrative costs. Actual procurement rates change monthly.

(c) CARE customers receive a 20 percent discount on transportation and procurement and are exempt from paying CARE surcharges.

(d) Transportation Only rates include: (i) a transportation component that recovers CCC, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a G-PPP surcharge that recovers the costs of low income CARE, LIEE, CEE, Research Development and Demonstration program and State BOE/CPUC Administrative costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

(e) Residential and Small Commercial Classes are 20 percent averaged.

(f) West Coast Gas is allocated 60 percent of its full distribution cost as of January 1, 2011.

TABLE 10-4
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE NONCORE CLASS AVERAGE PRESENT AND PROPOSED RATES
(ASSUMING NONCORE CUSTOMERS PAY CORE SMALL COMMERCIAL PROCUREMENT RATES)
($ PER THERM)

Line No.		Present June 2011 Rate(a)(b) ($/th)	Proposed 2012 Rates(a)(b) With Implementation Plan Costs ($/th)	Percentage Change
1	Customer Class Noncore			
2	Industrial Distribution	$0.689	$0.714	~~3.6~~3.7%
3	Industrial Transmission	$0.587	$~~0.612~~0.613	~~4.2~~4.3%
4	Industrial Backbone	$0.560	$~~0.562~~0.566	~~0.4~~1.0%
5	Electric Generation – Distribution/Transmission	$0.547	$0.572	~~4.6~~4.7%
6	Electric Generation – Backbone	$0.525	$~~0.527~~0.531	~~0.4~~1.1%
7	Noncore NGV Service – Distribution	$0.673	$0.698	~~3.7~~3.8%
8	Noncore NGV Service – Transmission	$0.573	$0.598	4.4%
9	Wholesale			
10	Alpine Natural	$0.544	$0.569	~~4.6~~4.7%
11	Coalinga	$0.544	$0.569	~~4.6~~4.7%
12	Island Energy	$0.545	$~~0.570~~0.571	~~4.6~~4.7%
13	Palo Alto	$0.543	$~~0.568~~0.569	~~4.6~~4.7%
14	West Coast Gas – Castle(c)	$0.618	$0.643	~~4.0~~4.1%
15	West Coast Gas – Mather Distribution(c)	$0.641	$~~0.666~~0.667	~~3.9~~4.0%
16	West Coast Gas – Mather Transmission	$0.544	$0.569	~~4.6~~4.7%

(a) Rates represent class average. Actual transportation rates will vary depending on the customer's load factor and seasonal usage. Rates are rounded to three decimal places for ease of viewing. Percentage rate changes are calculated on a 5-digit basis.

(b) Rates include: (i) an illustrative core small commercial procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual WACOG of $0.429 per therm; (ii) a transportation component that recovers CCC, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a G-PPP surcharge that recovers the costs of low-income CARE, LIEE, CEE, Research Development and Demonstration program and State BOE/CPUC Administrative costs. Actual core procurement rates change monthly.

(c) West Coast Gas is allocated 60 percent of its full distribution cost as of January 1, 2011.

E. Conclusion

PG&E's Implementation Plan cost allocation and rate proposal should be adopted by the Commission because it:

1. Apportions PG&E's authorized Implementation Plan Backbone Transmission, Local Transmission and Storage revenue requirements between core and noncore customers consistent with the core and noncore

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monthly bill for natural gas service. The cost of the pipeline system needed to transport and deliver the gas to customers is a small part of their gas bill.

Under PG&E's proposal, rates for bundled residential gas customers (customers who receive gas distribution and natural gas procurement services from PG&E) will increase in 2012 by 4.08 percent, and bundled small and large commercial gas rates will increase by 5.12 percent and 6.52 percent, respectively. A typical residential customer using 37 therms per month will see an average monthly bill increase of $1.85, from $45.23 to $47.08. A typical small business customer using 287 therms per month would see an average monthly bill increase of $14.33, from $279.80 to $294.13.

4. Ratemaking Approach

In the Implementation Plan, PG&E has proposed a number of ratemaking mechanisms and procedures to increase PG&E's accountability to the public and the Commission.

First, PG&E has proposed a forecast for capital and expense for Phase 1. This forecast would be binding on PG&E for the four-year period, unless the Commission authorizes a modification to the budget. Under this approach, if circumstances lead to a change in Phase 1 project scope, schedule or cost that would cause the program to exceed the Phase 1 forecast for expense or capital, PG&E would be required to submit an advice letter to the CPUC requesting a change in the project forecast. The public and interested parties would have an opportunity to comment on such a request. If the Commission decides not to modify the forecast in response to a request, PG&E would be required to manage and prioritize the remaining work scope within the approved forecast, potentially resulting in a shift of some projects to Phase 2 of the program.

Second, PG&E proposes to establish a balancing account to track expenditures and hold PG&E accountable to its plan. For capital expenditures, PG&E proposes to recover capital costs of a project in rates only after that project has been placed into operation and the actual costs of the project are known. Under this approach, PG&E would track the revenue requirements associated with capital expenditures after their project testing, approximately one-half mile of pipeline replacements and installation of 29 automated valves on the San Francisco Peninsula.

PG&E has reached out to customers and the community to improve communication and provide information about the natural gas transmission system. PG&E has created a new web page that provides gas system and safety information; now anyone can enter an address into the website to see if there is a transmission pipeline located nearby. PG&E also mailed more than two million letters to homes and businesses within 2,000 feet of a gas transmission line providing information about the proximity of gas transmission pipelines and additional safety information and resources. PG&E has held over 100 meetings with cities, counties and public groups to discuss gas safety issues and open lines of communication.

The IRP Report issued on June 8, 2011, raised a number of well-founded concerns about the way PG&E has managed its gas operations. It is clear from the report that PG&E needs to make major improvements in both its operations and culture. As recommended in the IRP Report, PG&E is in the process of establishing a new stand-alone gas operations organization. The new organizational structure will be announced shortly. As part of this process, PG&E is reexamining and retooling its entire organization, including its procedures, staffing, budget, and work priorities. PG&E will look to the top performers in the industry to benchmark best practices and evaluate PG&E's performance. In the past year, PG&E has hired 237 new gas engineering and operations and gas maintenance and construction staff and it is in the process of recruiting more new employees.

The Implementation Plan is an important part of PG&E's overall strategy to enhance safety and improve operations. The program works in combination with and complements our existing pipeline replacement and maintenance programs, Risk Management Program and TIMP and Distribution Integrity Management Program, all of which are already funded in rates under the GT&S rate case settlement (Gas Accord V, adopted by D.11-04-031) and the 2011 General Rate Case Settlement (adopted by D.11-05-018). These work streams are part of our coordinated Gas Operations strategy and plan to achieve world-class standards of safety and performance. Our goal is, by our actions, to regain the trust of the public that PG&E puts safety first.

using the manufacturing techniques available at the time. Generally, pipe manufactured today is considered a higher quality product than pipe manufactured 50 to 70 years ago.

The 1970 threshold date was selected to reflect improvements in several areas:

(a) Changes in pipe metallurgy, plate welding to form pipe (longitudinal welds), the increase of pipe mill test pressures and other pipe inspection criteria combined to minimize the threats associated with imperfections introduced in the pipe manufacturing process.

(b) Publication in 1970 of federal natural gas transportation pipeline safety regulations, 49 CFR Part 192. These regulations established minimum pipeline manufacturing, design, construction, testing, and maintenance and operation safety standards for all pipeline operators that further distinguish the pipe on either side of this date.

(c) The manufacturing threat is considered present in pre-1970 vintages of pipe with a manufactured long seam by low-frequency Electric Resistance Weld (ERW), spiral weld, Single Submerged Arc Weld (SSAW), A.O. Smith flash weld, lap weld, hammer weld, or any pipe with a longitudinal joint efficiency factor[7] less than one.

To reduce system susceptibility to this threat, the Decision Tree prescribes pipe replacement for pipeline segments that have not been strength tested to 49 CFR 192, Subpart J requirements, operate at a SMYS equal to or greater than 30 percent, and are located within urban populated areas. Pipeline segments operating below 30 percent SMYS, but within urban populated areas, are

[7] A longitudinal joint efficiency factor is the ratio of the strength of the pipe long seam joint, to the strength of the base metal of the pipe. A longitudinal joint efficiency factor of 1.0 indicates the strength of the long seam joint is equal or greater to the base metal of the pipe. A joint efficiency factor of less than 1.0 indicates the strength of the long seam joint is less than the base metal of the pipe, and thus the weak link in the pipeline system. Refer to Attachment 3B, Implementation Plan Decision Point Justification for further description and pipe tables for Longitudinal Joint Efficiency Factors.

- Second – Decreasing PIR (highest to lowest), broken out into four Tier Groups, top 25 percent of PIR work started first, second set of 25 percent of PIR work started second, etc.
- Third – Percentage of HCA pipe (HCA footage/total footage) within each project from highest to lowest.

This prioritization system will serve as the basis for developing an annual project schedule, but will change based on the schedule impacts discussed in the next section.

b. Scheduling

PG&E expects to complete approximately 350 unique projects during Phase 1. PG&E will consider the following when scheduling and executing Phase 1 projects:

(1) PG&E will schedule those projects in order of ascending margin of safety for the pipeline, considering interim safety enhancement measures and normal operating conditions, to ensure that public safety is the primary driver for schedule. PG&E will evaluate the interactive nature of the threats. While a single threat category may not pose a significant threat to the pipeline system, multiple threat categories on the same pipeline segment can contribute to a compounding effect, which may elevate the priority of any remedial measures.

(2) PG&E will schedule those projects that have a significant safety component in re-establishing operating pressures where pressure reductions would require curtailments of critical gas service.

(3) PG&E will schedule those projects with little or no expected permitting restrictions or delays. Conversely, for those projects with significant permitting challenges (e.g., endangered species and habitat), PG&E will begin engineering and permitting activities early in the Pipeline Program, since permitting on some pipe segments make take up to 18 to 30 months before construction can begin.

(4) PG&E will make reasonable efforts to schedule and sequence work in order to maintain customer service and minimize customer impact (outages).

estimate, PG&E has not included costs for any Supervisory Control and Data Acquisition or telecommunication work or repair. In addition, PG&E has added an allowance for replacing pipeline blow down stacks, line branch connections, and other existing line taps to each project.

(3) Indirect Costs

(a) Engineering, Design and Survey

Engineering, design, and surveying costs have been included at three percent of the material and construction costs, based on PG&E experience.

(b) Land and Right-of-Way

An allowance for ROW damages has been included based on land use. An allowance of 11 percent of the total estimated construction and material costs has been included in the non-congested areas to cover new ROW acquisitions (as necessary), ROW services, construction easements, and environmental mitigations. An allowance of 16 percent of the total estimated construction and material costs has been included in the semi-congested areas to cover new ROW acquisitions (as necessary), ROW services, construction easements, and environmental mitigation. An allowance of 6 percent of the total estimated construction and material costs has been included in the highly-congested areas to cover ROW services, construction easements, and environmental mitigations.

(c) Regulatory and Environmental Permitting

Regulatory and environmental permitting and service costs have been included at three percent of the material and construction costs, based on PG&E experience.

(d) Construction Management (Including Third-Party Inspection)

Construction management, construction inspection services, and quality control costs have been included at five percent of the material and construction costs.

The forecast summary by year and activity is summarized in Table 5-4 below.

TABLE 5-4
PACIFIC GAS AND ELECTRIC COMPANY
GTAM PROJECT FORECAST
($ IN MILLIONS)

Line No.		2011(a)	2012	2013	2014	Total
1	Capital	$7.4	$42.3	$27.2	$25.7	$102.6
2	Expense	0.5	5.8	7.5	7.2	21.0
3	Total	$7.9	$48.1	$34.7	$32.9	$123.6

(a) The 2011 expenses and capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011 will be funded by shareholders, as described in Chapter 8.

Table 5-5 below depicts the GTAM forecasts by phase.

TABLE 5-5
PACIFIC GAS AND ELECTRIC COMPANY
GTAM ASSUMPTIONS BY PHASE
($ IN MILLIONS)

Line No.	Phase	Forecast
1	Phase 0	$11.6
2	Phase 1	53.0
3	Phase 2	37.6
4	Phase 3	21.4
5	Total	$123.6

a. Assumptions

In general, the cost forecast for the GTAM Project assumes labor rates that are a blend of PG&E employees and third-party contractors. Process improvement and change management costs are assumed to be approximately 14 percent of the total forecast.

TABLE 9-1
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT REQUEST
($ IN THOUSANDS)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total
1	Capital-Only Revenue Requirement	–	$13,205	$63,981	$154,816	$232,002
2	Expense-Only Revenue Requirement	–	234,074	156,852	145,825	536,751
3	Total	–	$247,279	$220,833	$300,641	$768,753

Table 9-2 shows the requested base revenue requirements, broken down by gas department lines of business, for the years 2012, 2013 and 2014.

TABLE 9-2
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT
($ IN THOUSANDS)

Line No.	Gas Department Lines of Business	2011	2012	2013	2014	Total
1	GT – Local Transmission	–	$197,971	$180,049	$233,407	$611,427
2	GT – Backbone Transmission	–	44,827	36,978	58,408	140,213
3	GS – Storage	–	4,481	3,806	8,826	17,113
4	Total	–	$247,279	$220,833	$300,641	$768,753

B. Cost Structure

PG&E's Gas Transmission and Storage (GT&S) rates currently in effect are based on the Gas Accord V Settlement, approved by the California Public Utilities Commission (CPUC or Commission) on April 14, 2011 in Decision 11-04-031. PG&E generally has maintained the same cost structure in this Implementation Plan.

C. Operations and Maintenance Expenses

The Operations and Maintenance (O&M) expense estimates for 2011 through 2014 include labor, materials, supplies, contracts, and other expenses related to implementing the Implementation Plan. Chapters 3 through 7 provide the estimated amount of these expenses and describe the services provided. These expenses are estimated in nominal dollars. This is consistent with the method PG&E used in its 2011 General Rate Case (GRC) revenue requirements for capital projects and expenses are not included in rates.

TABLE 10-2
PACIFIC GAS AND ELECTRIC COMPANY
PROPOSED GAS PIPELINE SAFETY RATES
($ PER THERM)

Line No.		2012	2013	2014
1	Core	$0.04994	$0.04439	$0.05964
2	Noncore – Local Transmission/Distribution Level	$0.02547	$0.02276	$0.03184
3	Noncore – Backbone Transmission Level	$0.00569	$0.00480	$0.00808

D. Illustrative Gas Rate Impact Summary

Illustrative present (2011) and proposed annual average 2012 rates are summarized in Table 10-3 below. Illustrative bundled present core rates are based on gas transportation rates filed in PG&E's 2011 GRC decision (D.11-05-018) implementation core Advice 3206-G, effective June 1, 2011. Present noncore and wholesale rates are based on those filed in PG&E's 2011 GRC implementation noncore Advice 3207-G, effective June 1, 2011.

TABLE 10-3
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE CLASS AVERAGE PRESENT AND PROPOSED RATES
($ PER THERM)

Line No.	Customer Class	Present June 2011 Rate(a) ($/th)	Proposed 2012 Rates(a) With Implementation Plan Costs ($/th)	Percentage Change
1	Core Retail – Bundled(b)			
2	Residential (Non-CARE)(c)(e)	$1.223	$1.272	4.1%
3	Commercial, Small (Non-CARE)(e)	$0.975	$1.025	5.1%
4	Commercial, Large	$0.766	$0.816	6.5%
5	NGV Service – Compression on Customer Premises	$0.661	$0.711	7.6%
6	Compressed NGV Service	$1.912	$1.962	2.6%
7	Core Retail – Transportation Only(d)			
8	Residential	$0.650	$0.700	7.7%
9	Commercial, Small	$0.418	$0.468	11.9%
10	Commercial, Large	$0.248	$0.298	20.1%
11	Noncore – Transportation Only(d)			
12	Industrial Distribution	$0.171	$0.197	14.9%
13	Industrial Transmission	$0.069	$0.095	36.7%
14	Industrial Backbone	$0.042	$0.048	13.5%
15	Electric Generation – Distribution/Transmission	$0.029	$0.054	87.8%
16	Electric Generation – Backbone	$0.007	$0.013	76.4%
17	Noncore NGV Service – Distribution	$0.155	$0.180	16.5%
18	Noncore NGV Service – Transmission	$0.055	$0.081	46.2%
19	Wholesale – Transportation Only(d)			
20	Alpine Natural	$0.026	$0.051	99.1%
21	Coalinga	$0.026	$0.051	98.8%
22	Island Energy	$0.027	$0.053	92.9%
23	Palo Alto	$0.025	$0.051	100.7%
24	West Coast Gas – Castle(f)	$0.100	$0.126	25.4%
25	West Coast Gas – Mather Distribution(f)	$0.123	$0.149	20.6%
26	West Coast Gas – Mather Transmission	$0.026	$0.051	98.0%

(a) Rates represent class average. Actual transportation rates will vary depending on the customer's load factor and seasonal usage. Rates are rounded to three decimal places for ease of viewing. Percentage rate changes are calculated on a 5-digit basis.

(b) Bundled core rates include: (i) an illustrative procurement component that recovers intrastate and interstate backbone transmission charges, storage, brokerage fees and an average annual Weighted Average Cost of Gas (WACOG) of $0.429 per therm; (ii) a transportation component that recovers Customer Class Charge (CCC), customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (iii) where applicable, a G-PPP surcharge that recovers the costs of low-income California Alternate Rates for Energy (CARE), Low Income Energy Efficiency (LIEE), Customer Energy Efficiency (CEE), Research Development and Demonstration program and State Board of Equalization (BOE)/CPUC Administrative costs. Actual procurement rates change monthly.

(c) CARE customers receive a 20 percent discount on transportation and procurement and are exempt from paying CARE surcharges.

(d) Transportation Only rates include: (i) a transportation component that recovers CCC, customer access charges, CPUC fees, local transmission (where applicable) and distribution costs (where applicable); and (ii) where applicable, a G-PPP surcharge that recovers the costs of low income CARE, LIEE, CEE, Research Development and Demonstration program and State BOE/CPUC Administrative costs. Transportation only customers must arrange for their own gas purchases and transportation to PG&E's Citygate/local transmission system.

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