BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms (U 39 G)	Rulemaking 11-02-019

PACIFIC GAS AND ELECTRIC COMPANY'S NATURAL GAS TRANSMISSION PIPELINE REPLACEMENT OR TESTING IMPLEMENTATION PLAN

WILLIAM V. MANHEIM
KERRY C. KLEIN

Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-6628
Facsimile: (415) 973-5520
E-Mail: WVM3@pge.com
KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

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TABLE OF CONTENTS

Page

SB_GT&S_0354025

TABLE OF CONTENTS
(continued)

Page

SB_GT&S_0354026

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I. INTRODUCTION

Pacific Gas and Electric Company ("PG&E") files this Natural Gas Transmission Pipeline Replacement or Testing Implementation Plan ("Pipeline Safety Enhancement Plan" or "Implementation Plan") in compliance with Decision 11-06-017, issued June 9, 2011 by the California Public Utilities Commission ("CPUC" or "Commission") with the goal of enhancing safety and improving operations. Ultimately, when the Pipeline Safety Enhancement Plan is completed, PG&E will have comprehensively assessed all 5,786 miles of its natural gas transmission pipelines. This Pipeline Safety Enhancement Plan represents a clear break from the way California and its utilities approached pipeline safety in the past, and the way it will be approached in the future. The result of this effort will be tougher, safer standards for pipeline safety that will better serve PG&E's customers and the public.

Gas pipeline infrastructure in California and across the United States contains a wide range of pipeline types and vintages. Like other parts of our country's infrastructure, natural gas transmission pipelines were generally constructed with the best available design tools, technology, materials, and techniques. Over time, as those methods and materials improved, the

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regulations and codes governing the construction of pipelines have also evolved to require more effective inspection and control techniques, resulting in better quality and confidence in pipeline integrity. One of those changes, adopted by federal regulators in 1970, required all new gas transmission lines to have their Maximum Allowable Operating Pressure ("MAOP") established through rigorous pressure testing and records validation. However, the regulation "grandfathered" older pipelines, allowing their MAOP to be set according to their actual operating pressure over the previous five years. Following the San Bruno accident, the Commission has rightly insisted on a more rigorous standard for older pipelines. PG&E fully supports this new direction. Based on this order, PG&E has undertaken a massive and unprecedented program to pressure test or replace every pipeline without complete pressure test records and validate the MAOP of older pipelines through a rigorous, records-based analysis.

The actions and investments outlined in the Pipeline Safety Enhancement Plan are the roadmap for taking PG&E's pipeline safety to this new level. There are four main components to PG&E's Pipeline Safety Enhancement Plan:

(1) Pipeline Modernization – PG&E will establish a known margin of safety on every gas transmission pipeline segment and verify pipeline integrity through strength testing, pipeline replacement and pressure reductions, and will retrofit pipelines to accommodate the use of In Line Inspection ("ILI") tools.

(2) Valve Automation – PG&E will install automated valves in highly populated areas and where pipelines cross active seismic faults so gas can be remotely or automatically shut off in the event of a pipeline rupture. In addition, PG&E will upgrade its Supervisory Control and Data Acquisition ("SCADA") system to allow operators in its Gas Control Center to quickly detect a rupture and isolate nearby sections of pipeline.

(3) Pipeline Records Integration – PG&E proposes to transition away from reliance on traditional paper records and move to a fully electronic asset management system. PG&E will consolidate its gas transmission pipeline data and records systems, collect and verify all pipeline strength tests and pipeline features data necessary to calculate the MAOP for all gas transmission pipelines and associated components, and implement a new, electronic data management system that will enhance system operations, maintenance, inspections and regulatory compliance.

(4) Interim Safety Enhancement Measures – To enhance the safety margin of pipelines prior to testing or replacing them, PG&E has nearly completed MAOP validation for its HCA pipelines, has already reduced pressure on many pipelines, and increased the number of patrols and leak surveys. It will expand these interim safety enhancement measures and complete MAOP validation of its non-HCA pipelines under the Pipeline Safety Enhancement Plan.

The Pipeline Safety Enhancement Plan has two phases. Phase 1, which has already begun, will carry through 2014. It targets pipeline segments that are in highly populated urban areas, have vintage seam welds that do not meet modern manufacturing, fabrication or construction standards or were "grandfathered" under previous regulations, and have not been strength tested. During Phase 1, PG&E plans to replace 186 miles of transmission pipelines, strength test more than 780 miles, retrofit about 200 miles to permit in-line inspections, and in-line inspect over 200 miles. In addition, 228 gas shut-off valves will be replaced, automated and upgraded to enable PG&E to remotely or automatically shut off the flow of gas in the event of a pipe rupture.

Phase 2 will begin in 2015 and will target non-strength-tested urban pipelines without manufacturing threats operating below 30% Specified Minimum Yield Strength ("SMYS"), all non-High Consequence Area ("HCA") rural pipelines, and previously strength-tested pipelines (not tested to 49 CFR Part 192 Subpart J requirements). At its conclusion, PG&E will have assessed all 5,786 miles of its transmission pipelines and will have implemented industry-leading safety standards and practices for its entire system. We believe this work, under the CPUC's direction, will significantly enhance the integrity and operating safety margin of PG&E's natural gas transmission system and restore public confidence in the safety and integrity of PG&E's gas operations.

Through both phases of work, PG&E will conduct extensive customer and community outreach to inform the public, including local government officials, of any field activities that may impact them. PG&E will strive to minimize customer outages and public disruptions while working safely and ensuring strict regulatory and environmental compliance.

PG&E will also employ comprehensive program management to ensure quality and control costs. An External Program Advisory Board, made up of industry experts, will help monitor and oversee program performance. PG&E will deploy qualified union labor and will use a competitive process for contracted services.

PG&E seeks Commission approval of the work scope proposed for both Phase 1 and Phase 2 of the Pipeline Safety Enhancement Plan. However, this filing only requests cost recovery for Phase 1. Phase 2 timing and cost recovery will be addressed in a subsequent filing for rates effective January 1, 2015, consistent with PG&E's Gas Transmission and Storage ("GT&S") rate case cycle.

The actions and investments outlined in this Pipeline Safety Enhancement Plan present the roadmap for taking PG&E's system to the new, higher safety standards being set by the Commission. When these new standards are in place, California's pipeline safety rules will be the strongest in the country. PG&E forecasts spending approximately $2.2 billion to meet these new standards from 2011-2014, which results in revenue requirements of about $247 million in 2012, $221 million in 2013, and $300 million in 2014.[1/] The rate impacts are discussed in Chapter 10 of PG&E's prepared testimony, "Cost Allocation and Rates." Importantly, as shown on Table 1-1, PG&E's cost recovery request does not include more than one-half billion dollars in costs which will be absorbed by PG&E's shareholders. This shareholder allocation proposal does not address or resolve the historic recordkeeping issues being investigated by the Commission in the Gas Records OII.

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1/ The requested rate adjustment is significantly lower than the total expenditures because: (1) the rate recovery request has been reduced to reflect PG&E's shareholder allocation of Pipeline Safety Enhancement Plan costs; and (2) rate recovery for capital projects under the plan will be spread out over the useful lives of the capital assets, typically 40 years or more.

TABLE 1-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF SHAREHOLDER ALLOCATION
($ IN MILLIONS)

Line No.	Description	2010	2011	2012	2013	2014	Total
1	2011 Implementation Plan Work (a)						
2	2011 Expense Forecast (Including Contingency)	–	$220.7	–	–	–	$220.7
3	2011 In-Service Capital-Related Costs	–	1.4	–	–	–	1.4
4	Work On Post-1970s Pipe (b)						
5	Post-1970 MAOP Validation	–	38.5	$36.4	$11.0	–	85.9
6	Post-1970 Strength Testing	–	0.5	6.4	1.7	$3.2	11.8
7	Non-Implementation Plan Activities (c)	$63.3	152.1	–	–	–	215.4
8	Total Shareholder Cost Allocation	$63.3	$413.2	$42.8	$12.7	$3.2	$535.2

(a) PG&E proposes to have shareholders absorb all 2011 Pipeline Safety Enhancement Plan costs. Plan costs incurred in 2012-2014 would be eligible for cost recovery.

(b) Any costs for MAOP validation or strength testing of post-1970 pipelines will be absorbed by shareholders. PG&E is only seeking recovery for strength testing and MAOP validation costs for pre-1970 pipelines, which were "grandfathered" under existing federal regulations.

(c) Includes activities such as gathering gas system records and documents, leak survey and repair, emergency response, responding to requests for information and documentation, customer outreach, and supporting the NTSB, CPUC, and IRP investigations. PG&E expects to incur additional costs (at shareholder expense) in 2012-2014 related to these non-implementation plan activities, but does not have a forecast beyond 2011 at this time.

The Pipeline Safety Enhancement Plan also includes a number of procedures and reporting requirements that increase accountability and ensure that PG&E only receives funding for capital projects or expenses for projects or work that is completed. This precludes reallocation of funds earmarked for the Pipeline Safety Enhancement Plan to other utility uses. PG&E will regularly report to the CPUC and to the public our progress, including expenditures, budget forecasts and changes in scope and prioritization for projects.

As directed by the CPUC, this Pipeline Safety Enhancement Plan contains PG&E's proposed scope of work and prioritized schedule, as well as associated cost estimates and ratemaking proposals. PG&E also submits prepared testimony and workpapers, which provide more detail and explain the rationale behind the proposal. PG&E's cost estimates and project implementation schedule assume that PG&E receives Commission approval of Phase 1 early in 2012.

The Pipeline Safety Enhancement Plan[2/] is organized as follows:

Section II:	Pipeline Modernization Program
Section III:	Valve Automation Program
Section IV:	Pipeline Records Integration Program
Section V:	Interim Safety Enhancement Measures
Section VI:	Reporting Requirements
Section VII:	Cost Estimate and Ratemaking Proposal
Section VIII:	Notice and Service
Section IX:	Exhibits
Section X:	Conclusion

II. PIPELINE MODERNIZATION PROGRAM

A. Introduction and Overview

PG&E's Pipeline Modernization Program ("Pipeline Program") is a multiyear plan to eliminate the grandfathering for all gas transmission pipelines installed prior to 1970, and to validate the operating margin of safety on all Department of Transportation ("DOT")-defined gas transmission pipelines owned and operated by PG&E in California.

The Pipeline Program proposes to: (1) pressure test or replace all in-service natural gas transmission pipelines in California that do not have verifiable records of a pressure test in accordance with 49 CFR section 192.619, excluding subsection 49 CFR 192.619(c); (2) set forth criteria on which pipeline segments are identified for replacement instead of pressure testing; (3) provide a priority-ranked schedule for pressure testing and replacement of pipe not previously pressure tested; and (4) set forth criteria for use in deciding to retrofit pipelines to allow for ILI tools.

Phase 1 of the Pipeline Program, starting immediately, will focus on pipeline segments

2/ The Pipeline Safety Enhancement Plan is interchangeably referred to as the "Implementation Plan."

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that are operating within urban areas without a documented pressure test to 49 CFR 192 Subpart J requirements. It will cover pipeline segments within Class 2, 3, or 4 (whether HCA or not) and Class 1 HCA. Phase 2 will begin in 2015, and will focus on completing the rest of the work, primarily on non-strength-tested rural pipelines, urban non-strength-tested pipelines operating below 30% SMYS, and all previously tested pipelines that were not tested to 49 CFR Part 192 Subpart J requirements.

The Implementation Plan includes the methodology and criteria to be used to determine specific actions to be taken on each unique pipe segment, such as strength testing, replacement, and/or retrofitting for ILI, and a prioritization methodology for completing the work within Phase 1 and Phase 2. In addition, the Implementation Plan provides a high level summary of the work proposed for Phase 2. The scope, schedule, and cost recovery for Phase 2 of the Pipeline Program will be addressed in a future Commission proceeding.

More detailed descriptions, technical bases and cost estimates for the Pipeline Program work are provided in the accompanying testimony and workpapers supporting Chapter 3, "Gas Transmission Pipeline Modernization Program." Cost recovery for Phase 1 work is discussed in Chapter 8, "Cost Recovery." In addition, the need for flexibility in the work scope as new and better information is received about the transmission pipelines, as well as reporting requirements to track PG&E's progress against its forecasts, are also discussed in Chapter 8.

B. Pipeline Pressure Testing And Replacement Plan

1. Pipeline Threat Model And Methodology

PG&E's plan uses a deterministic model (i.e., "if this—then this") to identify and phase pipe segments for strength testing or replacement, if they have not been previously tested in accordance with 49 CFR 192.619, excluding 192.619 (c). The purpose of this approach is to appropriately schedule work based on the probability of failure for each pipe segment. This methodology was developed by PG&E engineers to address the greatest threats to older pipelines, in consultation with a leading industry expert, whose report is attached as Exhibit 3C to the accompanying testimony. The model is based on five industry recognized pipeline threats: (1) manufacturing-related threats; (2) fabrication and construction-related threats; (3) internal corrosion; (4) external corrosion; and (5) latent third-party and mechanical damage threats. Within each threat, additional decision criteria were added, such as verifiable strength testing records, SMYS at maximum operating pressure ("MOP"), and class location or HCA, to refine appropriate actions for each pipe segment.

The threat model and decision criteria methodology are contained below in the three Decision Trees (one for each of the pipeline threats, with internal/external corrosion and latent mechanical damage combined), and also on a single 11x17 page as Attachment 3A to Chapter 3 of the accompanying testimony. For a complete description of the Decision Tree and justification for its use, refer to Chapter 3 of the accompanying testimony, "Gas Transmission Pipeline Modernization Plan."

The Decision Trees were designed to assess for the threat at the pipe segment level. A pipe segment is any pipe component with consistent characteristics, such as pipe diameter, wall thickness, pipe grade, yield strength, year of installation, pipe coating, long seam type, girth joint type, girth weld method, MOP, HCA, pressure test date, pressure test medium, test pressure, and class location.

As a key part of the Pipeline Safety Enhancement Plan, every gas transmission pipe segment, including gas gathering pipe, has been analyzed with the Decision Tree to determine a recommended action — such as strength test, replacement of pipe, or ILI — to establish a known margin of safety. Each action is denoted by an "Action Box." Actions are prioritized as either

Phase 1 or Phase 2, as shown below. A brief summary of the decision criteria and recommended actions derived within each threat category is included below.

2. Decision Tree, Manufacturing Threats

The Decision Tree in Figure 2-1 addresses pipeline manufacturing threats. It identifies pipe segments whose integrity may be threatened as a result of the methods used to manufacture the pipe. Pipe vintage, long seam type, and proof of a past strength test are important considerations in this determination. The stress level at which each segment operates (SMYS at MOP), and its proximity to people are used to decide whether strength testing or pipe replacement is the appropriate mitigation measure.

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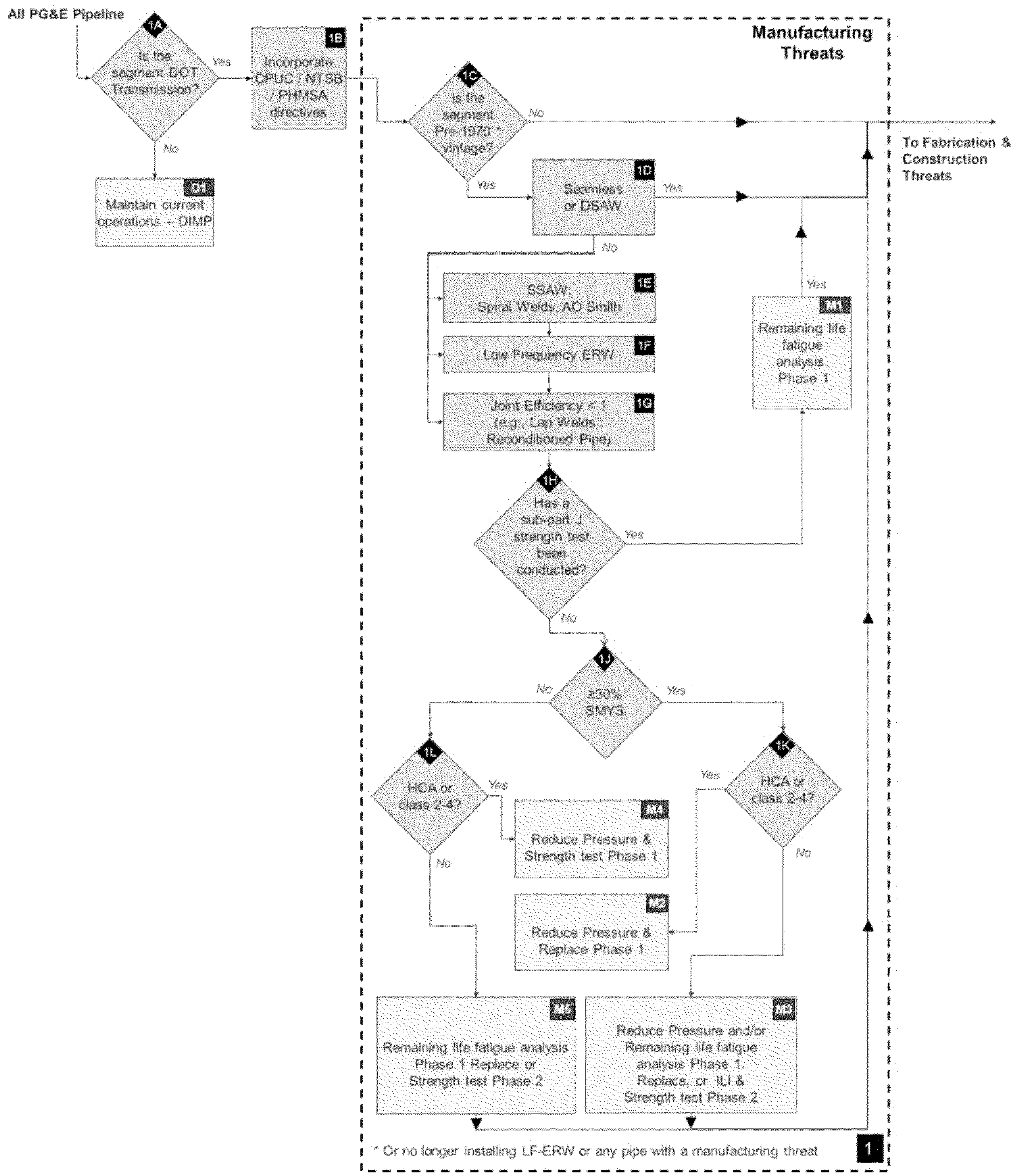
FIGURE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
MANUFACTURING THREAT DECISION TREE



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3. Decision Tree, Fabrication And Construction Threats

The Decision Tree in Figure 2-2 addresses pipeline fabrication and construction threats, particularly pipe joining methods and fittings. Pipe vintage, girth weld design and method, and proof of a past strength test are important considerations. As with manufacturing issues, the appropriate mitigation measure will depend on the stress level at which the segment operates, and its proximity to people.

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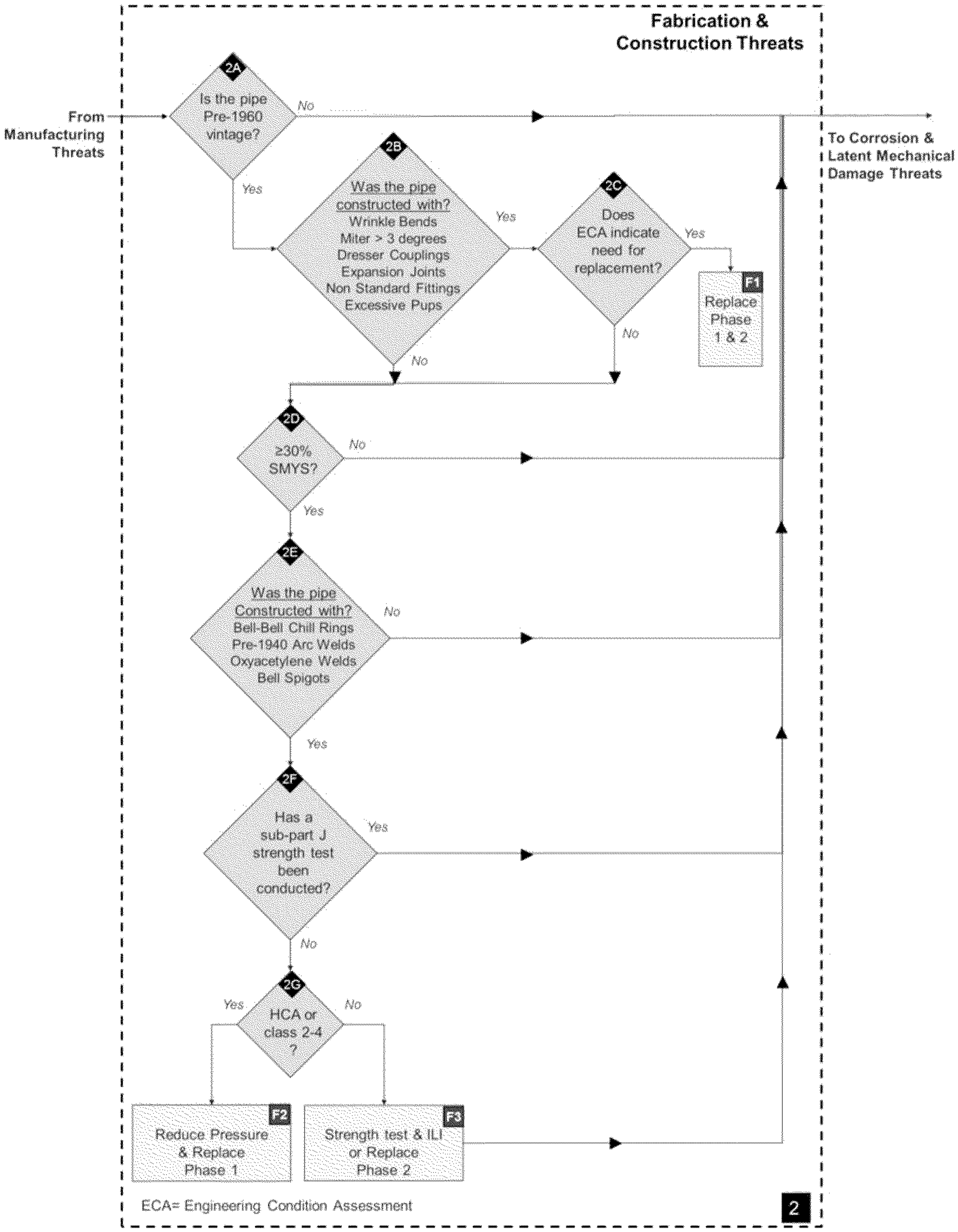
FIGURE 2-2
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
FABRICATION & CONSTRUCTION THREAT DECISION TREE



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4. Decision Tree, Corrosion And Latent Mechanical Damage Threats

The Decision Tree shown in Figure 2-3 addresses internal and external corrosion and latent third-party or mechanical damage.[3/] Again, appropriate mitigation measures will depend on the stress levels at which these segments operate, proximity to people, past pressure testing, and whether the segment was included in the Transmission Integrity Management Program ("TIMP"), pursuant to CFR 49 192 Subpart O.

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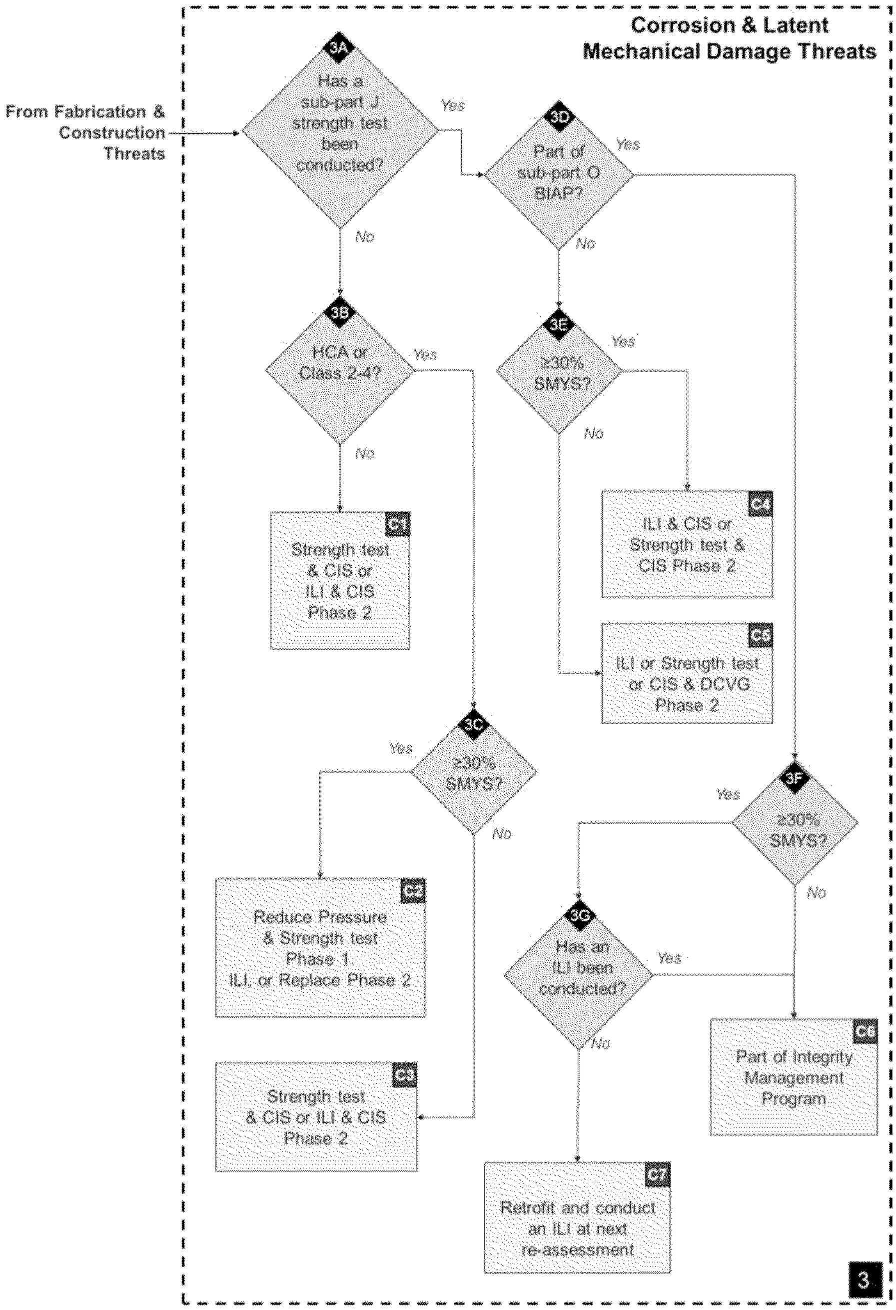
3/ Latent third-party or mechanical damage refers to damage to PG&E pipelines that is unknown to PG&E because the party that caused the damage was either unaware that the damage occurred, or chose not to report that the damage had occurred.

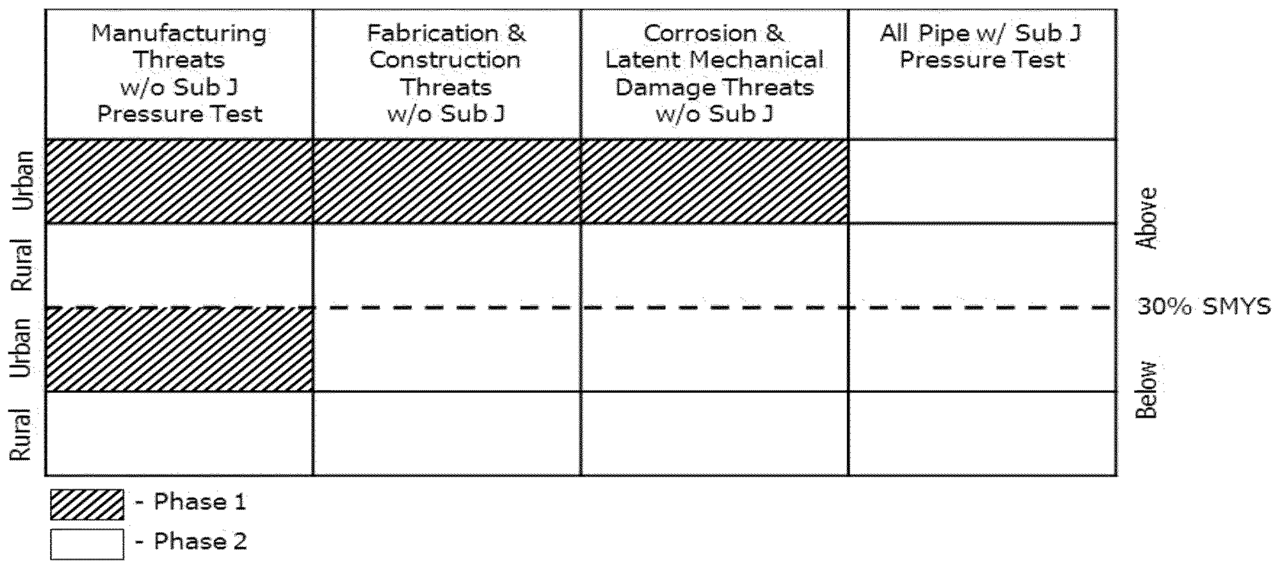
FIGURE 2-3
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
CORROSION & LATENT MECHANICAL DAMAGE THREAT DECISION TREE



5. Prioritization Of Segments For Pressure Testing Or Replacement

The Decision Trees provide the foundation for prioritizing the Pipeline Modernization Plan into two phases. Phase 1 consists of pipe segments within urban areas that have not been previously strength tested (or for which records of a strength test cannot be verified). "Urban area" for the purpose of Phase 1 of the Pipeline Program consists of Class 2, 3, and 4 and Class 1 HCA pipe. Phase 2 completes the rest of the work specified by the Decision Tree, which includes the non-strength-tested rural pipelines, urban non-strength tested pipelines operating below 30% SMYS, and all previously strength tested pipelines. Figure 2-4 depicts graphically the scope of work within Phase 1 and Phase 2.

FIGURE 2-4
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
PIPELINE SCOPE PER PHASE



Phase 1 work is composed of three specific actions: pipe replacement, strength testing and ILI. Within each work type, individual projects are then scheduled to ensure the pipe segments with the highest priority and public safety exposure are completed early in the program phase.[4/] Project prioritization criteria used include class location, Potential Impact Radius

4/ Prioritization is not done on a "1 through n" basis, but rather on an annual basis. The schedule of work within any given year will be determined by operational needs, other planned work, environmental and other considerations.

("PIR")[5/] and inclusion in an HCA, and are discussed in more detail in Chapter 3.

PG&E's project prioritization model will serve as the basis for developing an annual project schedule, but the sequence of project completion will change based on other factors such as public safety, project routing, permitting environmental considerations, efforts to schedule work to minimize service interruptions to customers, scheduling integration with other planned work and third party utilities, weather, geographic location, and efficient use and mobilization of resources.

6. Decision Tree Results – Work To Be Completed By The Pipeline Modernization Program

The Phase 1 scope is based on information from PG&E's gas transmission Geographic Information System ("GIS") and updated pipeline information from the MAOP Records Validation Project as of June 30, 2011. Due to the inherent uncertainty of estimating these costs (e.g., unknowns such as land ownership (easement/franchise), biological surveys for threatened and endangered species and cultural resources, general public and elected official engagement, construction equipment access and permitting restrictions), PG&E also has included appropriate contingency requests with this submission. On average, the contingency is about 21% of the estimated cost. The contingency is addressed in Chapter 7, "Implementation Plan Management Approach and Estimate Risk Quantification."

Table 2-1 reflects PG&E's estimated schedule and costs, without contingency. Project-specific details are provided in Chapter 3 of the accompanying testimony, "Gas Transmission Pipeline Modernization Program" and in the associated workpapers and attachments. As

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5/ PIR generally refers to the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is a function of the pipe diameter and the pressure of the natural gas in the pipe, and is proportional to the heat intensity of the initial flame should a pipeline rupture ignite.

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discussed in Chapters 3 and 8, this schedule may need to be adjusted as more information becomes available.

TABLE 2-1
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE MODERNIZATION PROGRAM
ESTIMATED COSTS BY WORK TYPE IN PHASE 1 (2011-2014)

Line No.	Work Description	2011(a)	2012	2013	2014	Total
1	**Strength Testing**					
2	Miles	236	185	204	158	783
3	Capital Expenditures ($ in millions)	$16.2	$15.7	$15.8	$15.9	$63.6
4	Expenses ($ in millions)	$121.1	$93.7	$84.5	$93.9	$393.2
5	**Pipeline Replacement**					
6	Pipeline Replacement Miles	0.3	39	64	82	186
7	Capital Expenditures ($ in millions)	$15.5	$198.6	$280.1	$340.0	$834.2
8	Expenses ($ in millions)	$1.6	$1.2	$1.0	$1.1	$4.9
9	**ILI Upgrades**					
10	Miles	–	92	107	–	199
11	Capital Expenditures ($ in millions)	$1.1	$14.6	$14.6	–	$30.4
12	**In-Line Inspections**					
13	Miles	–	–	78	156	234
14	Expenses ($ in millions)	–	–	$1.7	$7.9	$9.6
15	**Total**					
16	Total Miles Strength Tested or Replaced	236	224	268	240	968
17	Total Miles Strength Tested, Replaced, ILI upgrades	236	316	375	240	1,167
18	Total Capital Expenditures ($ in millions)	$32.8	$228.9	$310.5	$355.9	$928.1
19	Total Expenses ($ in millions)	$122.7	$94.9	$87.3	$102.8	$407.7

(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.

7. Strength Testing

Based on the Decision Trees, PG&E proposes to strength test about 783 miles of pipe segments in Phase 1. The tests will be conducted in accordance with 49 CFR, Subpart J requirements.

a. Phase 1 Strength Testing

Phase 1 strength testing[6/] addresses the following types of pipe:

- Pipe manufactured by processes known to produce less robust weld seams by current standards, or weld seams with poor fracture toughness. These include pre-1970, low-frequency electric resistant weld ("ERW"), flash welded, single submerged arc weld ("SSAW"), furnace butt welded, and lap welded pipe operating between 20% and 30% SMYS in urban areas.
- All urban-area pipes operating at or above 30% SMYS, without an adequate strength test, unless scheduled for replacement.

b. Phase 2 Strength Testing

During Phase 2, PG&E forecasts the need to strength test an additional 1,700 miles of pipeline. The following types of pipe will be tested during Phase 2:

- All urban area pipes operating below 30% SMYS, without an adequate pressure test, that are not scheduled to be replaced.
- All identified pipe not previously strength tested or replaced in Phase 1, which includes pipe located in Class 1 non-HCA (rural areas) without an adequate pressure test.

In addition, strength testing may also be used as a means to ensure the previously measured safety margin has not been jeopardized during the pipe's service life.

8. Pipeline Replacement

a. Phase 1 Pipeline Replacement

As a result of its analysis and prioritization, PG&E estimates that it will replace 186 miles

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6/ PG&E will use hydrostatic testing for most of its Phase 1 strength tests. In rare exceptions, PG&E may use inert gas where doing so complies with federal pipeline regulations.

of pipeline during Phase 1 of the Pipeline Program. During Phase 1, PG&E will replace the following types of pipe:

- Pipe manufactured by processes generally thought to produce less robust weld seams by current standards, or weld seams with poor fracture toughness, including pre-1970, low-frequency ERW, flash welded, SSAW, furnace butt welded, lap welded, and hammer welded pipe operating at or above 30% SMYS in urban areas.
- Pipelines constructed with welding techniques generally thought to produce low toughness or girth welds such as oxygen-acetylene welds, bell-to-bell chill ring welds, bell and spigot welds, and pre-1940 arc welds operating at or above 30% SMYS in urban areas.

b. Phase 2 Pipeline Replacement

During Phase 2, PG&E will replace the following types of pipe:

- Pipe operating above 30% SMYS with any features whose presence may interfere with effective and successful ILI that can reliably assess for a multitude of other important integrity concerns.
- Any pipe that is determined unlikely to pass the required 49 CFR 192 Subpart J strength test.[7/]
- Any pipe constructed with obsolete pipe joining methods or fittings for which an engineering condition assessment indicates a need for replacement.

The rate of pipeline replacement within Phase 2 is forecasted at 25 to 50 miles per year.

7/ PG&E anticipates that some pipeline segments will fail a strength test, and will therefore need to be replaced. This is a placeholder in anticipation of that additional pipeline replacement.

9. In-Line Inspection

As part of the Pipeline Program, PG&E proposes to retrofit all pipelines operating above 30% SMYS, and many below 30% SMYS, to accommodate inspections using current intelligent "pigging" technologies. The majority of ILI work will be conducted in Phase 2. Phase 1 includes 199 miles of pipeline retrofit for ILI and 234 miles of actual in-line inspections (or "ILI runs"). These ILI pipeline segments are located on the L-300 backbone system and on three urban pipelines located within the South Bay and San Francisco Peninsula.

The system-wide ILI program will be used to provide assurance that the margin of safety from any previously conducted strength test has not been compromised since the time of the test. Where ILI is not feasible in pipelines operating below 30% SMYS, PG&E will continue strength testing, pipe replacement, or other actions to assure the margin of safety is not compromised. As a result of the Decision Tree analysis, PG&E forecasts the percentage of total pipeline miles retrofitted for ILI to increase from 22% to 26% by the end of Phase 1 (2014), and to 70% of the gas transmission system by the completion of Phase 2.

III. VALVE AUTOMATION PROGRAM

A. Introduction and Overview

This section of PG&E's Implementation Plan describes PG&E's Valve Automation Program. The objective of the Valve Automation Program is to minimize the potential consequences of an extended duration natural gas-fueled fire created by a gas pipeline rupture (and work in concert with first responders) by expanding the use of automated gas transmission pipeline system isolation valves ("automated valves"). There are two types of automated valves included in the program: (1) Remote Control Valves ("RCV"); and (2) Automatic Shut-off Valves ("ASV"). PG&E will install RCVs, which are remotely closed by operators in the Gas Control Center, in heavily populated areas. PG&E will prioritize installation of RCVs on pipeline segments based on population density (i.e., class location, presence of HCA, and PIR). In addition, PG&E will install ASVs, which are automatically closed by local controls at the valve site, on pipelines in populated areas that cross active earthquake faults where the fault poses a potentially significant threat to the line. A detailed description of RCV and ASV criteria is included in Chapter 4 of PG&E's testimony accompanying the Implementation Plan, "Gas Transmission Valve Automation Program."

As part of the Valve Automation Program, PG&E will enhance its SCADA system to allow operators in its Gas Control Center to quickly detect a rupture and isolate the affected section of pipeline. The program will also replace valves being automated where needed to assure that the pipeline is capable of in-line inspection. RCVs will be designed so they can also be ASVs should design criteria or system parameters change.

PG&E will implement the Valve Automation Program in two phases. This Implementation Plan presents the proposed locations, schedule and cost estimates for Phase 1 implementation (2011-2014). In addition, the Implementation Plan provides a preliminary overview for the Phase 2 implementation (2015 and beyond). The scope, schedule and cost recovery for Phase 2 of the Valve Automation Program, beginning January 1, 2015, will be addressed in a subsequent proceeding.

B. Pipe Segment Selection for Automation

This section describes two decision trees — one based on population density and the other based on earthquake fault crossings — to determine which pipe segments should be equipped with automated isolation capability. These decision trees were developed as a result of extensive benchmarking both nationally and internationally, and in consultation with a leading industry expert. The main focus of the Valve Automation Program is retrofitting existing gas transmission lines. However, PG&E will also evaluate all new pipeline projects and replacement pipeline projects for valve automation.

1. Criteria For Installation of RCVs In Highly Populated Areas

PG&E proposes to install RCVs on DOT-defined gas transmission pipeline segments within Class 3 and 4 areas and Class 1 and 2 HCAs that exceed minimum threshold criteria for pipe size and operating pressure as defined using a PIR calculation. For more populated Class 3 HCA and Class 4 areas, the minimum threshold criteria are reduced to recognize the higher potential consequence.

Specifically, PG&E will install RCVs on all DOT-defined gas transmission pipelines within Class 3 and 4 areas that meet one of these criteria:

(1) PIR > 200 feet for pipe located in Class 3 areas.
(2) PIR > 150 feet for pipe segments located in areas with a predominance of Class 3 HCA.
(3) PIR > 100 feet for pipe located in Class 4 areas.

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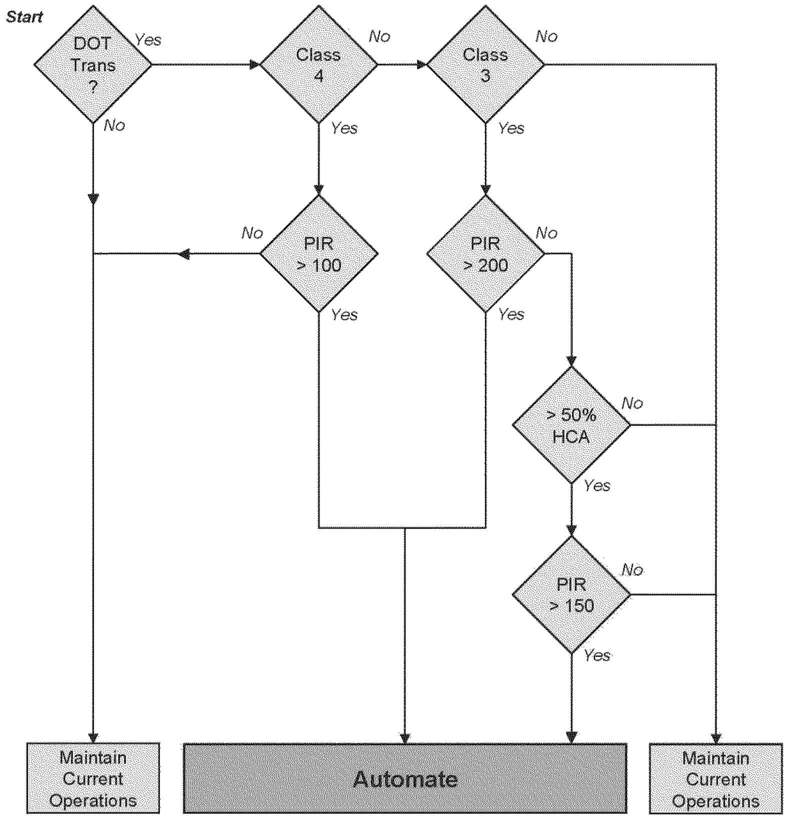
The following decision tree illustrates the evaluation of population density:

FIGURE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
DECISION TREE – POPULATION DENSITY



2. Criteria For Installation of ASVs at Earthquake Fault Crossings

PG&E will install ASVs on DOT-defined gas transmission pipelines within Class 3 and 4 areas and HCA Class 1 and 2 areas that exceed minimum threshold criteria for pipe size and operating pressure, and cross active faults that have a significant probability of rupturing a pipeline under maximum anticipated seismic event conditions.

PG&E will install ASV capability on all pipeline segments crossing active earthquake faults that meet the following criteria:

- The segment is in a Class 3, Class 4, or Class 1 or 2 HCA location, and the line segment had a PIR of greater than or equal to 150 feet.

- The earthquake fault is deemed a significant risk of causing a pipeline rupture as defined by the potential magnitude and likely frequency of a major earthquake event and the susceptibility of the pipe segment to rupture during a major event.
- The earthquake fault is considered active and is identified as having a greater than two percent probability of a 6.7 or greater magnitude earthquake event within the next 30 years.
- The rupture risk to the pipeline has not been mitigated by pipeline design.
- For pipelines crossing earthquake faults in sparsely populated areas, such crossings are included in an existing PG&E program[8/] that addresses design of pipelines crossing active earthquake faults, and are not part of the Valve Automation Program.

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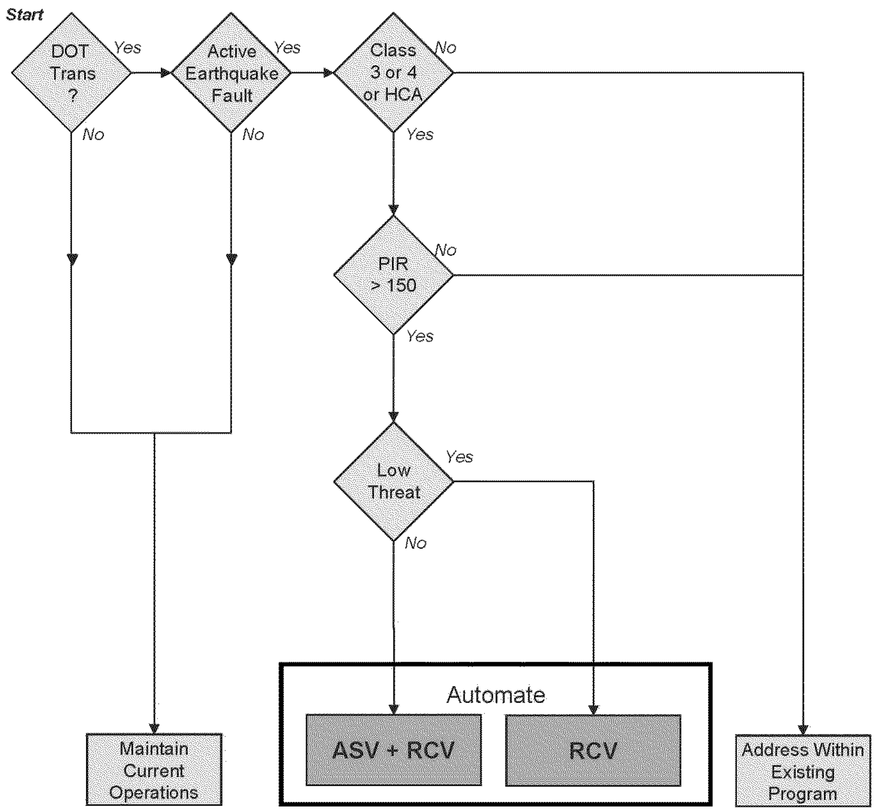
8/ Under an existing program that has been in place for many years, PG&E reviews whether the risk of rupture due to an earthquake can be mitigated by design, i.e., the pipeline segment crossing the fault is re-designed to withstand the maximum displacement expected from a fault rupture. This is a different and complementary mitigative measure to installing automated valves.

FIGURE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
DECISION TREE – EARTHQUAKE FAULT CROSSING



There are two alternatives within the "Automate" box of the earthquake fault crossing decision tree. Where crossings are deemed a potentially significant threat to the pipeline, ASVs will be installed that will also have RCV capability. These valves will closely bracket the fault. Where only a low threat exists, the fault crossing will be able to be isolated with RCVs installed at the same general spacing as for valves equipped with RCVs in the Population Density Decision Tree.

C. Automated Valve Spacing

The objective of the Valve Automation Program is to enable PG&E to quickly shut off the flow of gas in response to a gas pipeline rupture.

The following guidelines apply to the Valve Automation Program:

- Valve spacing distances should limit the potential number of customers being fed off of a pipe segment to no more than 50,000.
- The maximum spacing between valves is targeted to be:

  For Class 3 locations – 8 miles

  For Class 4 locations – 5 miles

In general, these guidelines utilize the valve spacing requirements specified in the CFR for pipelines in Class 3 and 4 areas, and then it was confirmed that utilizing these criteria as the maximum spacing requirements did not substantially increase the total overall anticipated time to isolate and vent gas in the event of a pipeline rupture. Generally, these guidelines target less than 10 minutes for blowdown for a full pipeline rupture.

In either case, the maximum distance may be slightly exceeded, to permit a valve to be automated in a way that is more accessible or minimizes public impact. Where automatic valves are installed at earthquake fault crossings, these valves will closely bracket the fault.

D. Pipe Segment Prioritization

Determination of phase priorities was based on two primary factors: population density and PIR. Table 3-1 shows the various miles of PG&E gas transmission pipeline by class, HCA and PIR value, and highlights the focus of Phases 1, 2A and 2B.

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TABLE 3-1
PACIFIC GAS AND ELECTRIC COMPANY
PIPE MILES BY PIR, CLASS AND HCA

Line No.	PIR	HCA Class 3&4	Non-HCA Class 3&4	Class 3&4 Miles	HCA Class 1&2	Non-HCA Class 1&2	Total Miles
1	501+	132(a)	23(c)	155	56	1,806	2,016
2	301-500	208(a)	68(c)	277	10	394	680
3	251-300	98(b)	41(c)	139	3	289	431
4	201-250	133(b)	71(c)	204	4	313	521
5	151-200	153(b)	128	281	4	284	569
6	101-150	161	268	430	3	453	886
7	0-100	60	179	239	1	418	658
8	Totals	947	778	1,715	80	3,958	5,763

(a) Focus of Phase 1.

(b) Focus of Phase 2A.

(c) Focus of Phase 2B. Phase 2B also includes unsustained pipe lengths of Phase 1 & 2A segments.

Note: The pipe mileage table is based upon a January 3, 2011 GIS database snapshot for all DOT gas transmission designated pipe (not including Gas Gathering). All mileage statistics for the Valve Automation Program and pipe segment analysis are based upon this data snapshot.

E. Phase 1 Valve Installations

Figure 3-3 highlights the core area of Phase 1 valve automation work. Approximately 60% of the miles slated for valve automation in Phase 1 are located in the Peninsula, South East Bay and South Bay. Other significant areas of work include Sacramento, Stockton, Fairfield, Bakersfield and Morgan Hill, and the Highway 4 corridor between Antioch and Highway 80 in the East Bay. All sites identified by symbols (i.e., circles, squares and triangles) are locations where specific types of valve automation work will be implemented as part of Phase 1.

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FIGURE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
MAP OF CORE PHASE 1 VALVE AUTOMATION

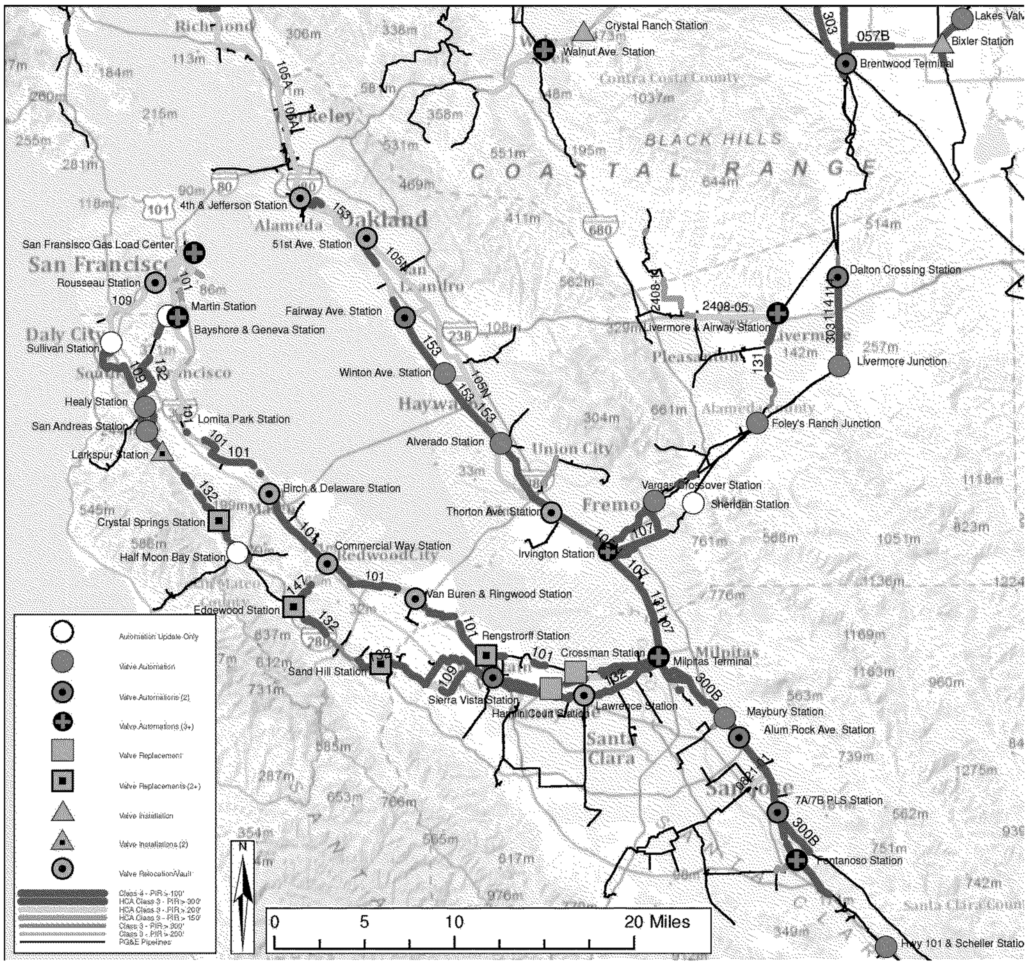

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Table 3-2 provides additional details on the specific valve automation work by year and geographical area.

TABLE 3-2
PACIFIC GAS AND ELECTRIC COMPANY
VALVES AUTOMATED BY AREA IN PHASE 1 (2011-2014)

Line No.	Geographical Area	Existing Valves Automated	Replaced or New Valves Automated	Automated Valves Upgrade	Total Valves Automated in Phase I
1	Peninsula (2011 Construction)	12	8	9	29
2	Peninsula (2012 Construction)	12	17	10	39
3	San Jose	13	2	6	21
4	Antioch to Richmond	27	7	3	37
5	Oakland to Fremont to Livermore	20	4	2	26
6	Brentwood Area	3	5	5	13
7	Sacramento Area	6	5	1	12
8	Vallejo-Fairfield Area	15	2	0	17
9	Stockton-Modesto Area	17	0	1	18
10	Bakersfield Area	5	0	2	7
11	Eureka Area	3	0	2	5
12	Barstow Area	2	0	2	4
13	Total	135	50	43	228

Note: Based upon preliminary analysis of existing valve installation conditions.

F. SCADA Enhancements

To ensure proper use of automated valves, the Pipeline Safety Enhancement Plan will provide Gas Control Operators with additional information, tools, and training to help them quickly detect and respond to pipeline ruptures. As part of this program, SCADA enhancements include:

1. Additional SCADA monitoring points for pressures and flows.
2. Detailed SCADA viewing tools that provide a comprehensive understanding of individual pipeline conditions in real-time, the potential effects (e.g., downstream pressures and flows) if a pipeline segment is isolated, and pipeline configuration and constraints.
3. Specific pipeline segment shutdown protocols to provide clear instructions on actions to be taken to quickly and effectively isolate a segment.

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4. Situational awareness tools, which utilize advanced composite alarming, and best practice alarm management methodology to highlight issues requiring immediate operator action.
5. Interactive tools that will allow operators to quickly access GIS physical pipeline information in relationship to SCADA points, and to geographically locate SCADA points.
6. Training simulation tools to prepare gas operators for potential line rupture scenarios.

These enhancements will be done in alignment with work on Control Room Management. In addition, as recommended by the Independent Review Panel, PG&E will conduct a study to evaluate potential SCADA expansion and improvement. As part of this assessment, PG&E will hire an external expert to review PG&E's gas SCADA system, and best practices for the use of SCADA systems by other gas pipeline companies and related industries. A description of the study scope is included in Chapter 4 of PG&E's testimony accompanying the Implementation Plan, "Gas Transmission Valve Automation Program."

G. Phase 1 Valve Automation Program Costs

The Valve Automation Program consists of capital and expense work. The capital work is primarily related to the valve automation projects. The expense work consists of SCADA enhancement projects, including additional Gas Operator training requirements, and recurring incremental operating and maintenance ("O&M") expenses associated with the new equipment. Due to the highly varying degree of accuracy for these estimates, contingency is addressed on a program level in Chapter 7, "Implementation Plan Management Approach and Estimate Risk Quantification." No contingency was included in individual project cost estimates. Table 3-3 provides an overview of the total forecasted costs, without contingency. Project-specific details are provided in Chapter 4 of the accompanying testimony, "Gas Transmission Valve Automation Program," and in the associated workpapers and attachments.

TABLE 3-3
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION PROGRAM
COSTS BY WORK TYPE IN PHASE 1 (2011-2014)
$ IN MILLIONS (NOMINAL)

Line No.	Work Description	2011(a)	2012	2013	2014	Total
1	Capital Expenditure Request					
2	Valve Automation	$13.6	$33.4	$43.2	$22.5	$112.7
3	Valve Automation-StanPac	–	2.0	4.6	–	6.6
	Flow Meter Installations	–	3.9	5.3	3.3	12.5
4	SCADA Enhancements	0.1	0.2	0.2	0.2	0.7
5	Valve Automation – Total Capital Expenditures	$13.7	$39.5	$53.3	$26.0	$132.5
6	Expense Request					
7	SCADA Enhancements	$0.8	$1.8	$1.8	$2.2	$6.6
8	Reoccurring Operations and Maintenance	–	0.8	1.3	1.6	3.7
9	Program Planning and Development	0.8	–	–	–	0.8
10	Valve Automation – Total Expenses	$1.6	$2.6	$3.1	$3.8	$11.1
11	Valve Automation Total (Capital and Expense)	$15.3	$42.1	$56.4	$29.8	$143.6

(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.

IV. PIPELINE RECORDS INTEGRATION PROGRAM

A. Introduction and Overview

The objective of the Pipeline Records Integration Program is to: (1) validate the MAOP of PG&E's gas transmission pipelines based upon the pipeline features data ("MAOP Project"); and (2) substantially upgrade gas transmission processes and record management infrastructure, allowing PG&E to transition from reliance on traditional paper records and consolidate pipeline information into two electronic information systems (SAP and GIS) ("Gas Transmission Asset Management," or "GTAM" Project). Included within the scope of the project is the development of new business processes and mobile computers intended to allow field maintenance and construction crews to improve the quality and efficiency of future information collected about the gas transmission system to support future operations, maintenance and risk management decision making. This program is described in greater detail in Chapter 5 of the accompanying testimony, "Pipeline Records Integration Program."

B. MAOP Project

PG&E will collect and verify all pipeline strength tests and pipeline features data necessary to re-calculate the MAOP of pipelines and all associated components. The original source documentation, which includes the characteristics and specifications of each pressure-containing component of the pipeline, is used to support the MAOP calculation for each component, and the resulting MAOP for each pipeline. The inventory will include electronic links to source information about each pipeline and each component in order to enhance transparency to the source used to derive critical data.

Given the scale of this effort, the MAOP Project is separated into three parts, with interim deliverables defined along the way. The three parts will be executed in sequential order per a priority established based on perceived potential risk.

The first part of the MAOP Project involved a comprehensive search of records to locate and scan all strength test records in an interim electronic database for all Class 3 and 4 pipeline segments, plus all HCA segments in Class 1 and 2, for a total of 1,805 miles. PG&E is not requesting cost recovery for Part 1. Part 2 of the MAOP Project is currently underway and is focused on validating the MAOP for HCA pipelines. PG&E is not seeking cost recovery of the MAOP validation of pipelines installed after 1970. Part 3 consists of MAOP validation of all remaining gas transmission pipelines in PG&E's system. It is anticipated that the MAOP Validation work will be completed in 2013.

C. Gas Transmission Asset Management Project

The GTAM Project will substantially enhance and improve: the amount and the types of information that PG&E collects and maintains electronically about its pipeline system; the business processes for collecting, validating and retaining pipeline data; the traceability of materials used in the construction and maintenance of PG&E's natural gas transmission pipelines; and PG&E's ability to assess and mitigate potential public safety risks.

The GTAM Project establishes a technology infrastructure that supports enhanced new business processes to ensure data reliability is maintained (on an ongoing basis beyond the completion of the Pipeline Records Integration Program) and enables improved decision making capabilities related to the risks and integrity of the gas transmission system. There are four primary objectives of the project.

First, all asset data (location/connectivity, specification/features, and maintenance/inspection history) are tracked, managed, and stored using a software product and data management technique called linear referencing, which is a best practice for viewing/analyzing pipeline features, characteristics, and event history relative to specific reference points along the entire length of gas transmission pipelines.

Second, materials are tracked in a traceable chain from receipt by PG&E through the operating life of the component. Key features that would be tracked include the manufacturer, characteristics of the component, manufacturer ratings, and factory test results.

Third, work management and data capture pertaining to maintenance and inspection processes (including Mark and Locate and Leak Survey) are more efficient, accurate, timely, and complete with rigorous quality assurance embedded. This will be accomplished by eliminating paper-based maintenance and inspection work processes and implementing automated work processes that manage Leak Survey, Mark and Locate, and preventative/corrective maintenance work from scheduling of work, field capture of information, verification/quality review of field-captured data, through updating of the Core Systems.

Fourth, tools are in place that enable integration of all underlying asset data (including event history such as leaks, dig-ins, etc.) to provide the full picture of asset health and condition with ability to perform risk and integrity analytics.

The implementation schedule for the GTAM Project includes a series of four distinct phases, over a period of approximately 3.5 years (fourth quarter 2011 through first quarter 2015). A more detailed schedule and cost information can be found in Chapter 5.

V. INTERIM SAFETY ENHANCEMENT MEASURES

A. Introduction and Overview

PG&E's Implementation Plan includes the following interim safety enhancement measures, in addition to the MAOP validation discussed above: (1) pressure reductions; and (2) increased leak surveys and patrols. Each activity is discussed in Chapter 6 of the accompanying testimony, "Interim Safety Enhancement Measures."

B. Interim Pressure Reductions as an Interim Safety Enhancement Measure

An interim pressure reduction may be called for on a pipeline segment under the following circumstances: (1) the MAOP Validation process (described above) identifies a segment where the calculated MAOP is lower than current operating pressure and pressure should be reduced to the calculated MAOP on an interim basis; or (2) the Pipeline Program Decision Trees identify an interim pressure reduction as a recommended mitigation measure. This section addresses how PG&E will coordinate and implement such interim pressure reductions under the Implementation Plan.

First, the MAOP Validation process may identify the need to take an interim pressure reduction on a pipe segment. Under this process, an MAOP will be calculated for each segment that has not been pressure tested. If the MAOP Validation determines that the MAOP should be lower than current operations, PG&E will take action to implement an interim pressure reduction on the segment. These interim pressure reductions will remain in effect until the pipe segment is tested or replaced under the Pipeline Program.

Second, under the Pipeline Program Decision Trees, the recommended action for some pipeline segments is to reduce pressure on an interim basis until a later corrective action can be accomplished. If a pressure reduction is indicated for a pipe segment under the Pipeline Program Decision Trees, PG&E will reduce the operating pressure on that segment by 20 pounds per square inch gauge ("psig") below the segment MAOP until corrective actions have been accomplished.

PG&E has specific design criteria standards to avoid customer outages and ensure safe and reliable service. Any interim pressure reduction implemented under the Implementation Plan will consider the safety impacts of customer outages along with pipeline integrity safety margins. PG&E will reduce operating pressure on a segment indicated by the Pipeline Program Decision Tree by 20 psig below MOP, provided that design criteria standards can be met, thereby avoiding the safety issues associated with customer outages. If the design standard cannot be met with the 20 psig interim pressure reduction, PG&E will reduce pressure to a level at which the design standard can be met. PG&E has already implemented certain interim pressure reductions and will complete its implementation of interim pressure reductions called for in the Pipeline Modernization Program Decision Trees no later than 30 days after final CPUC approval of the Implementation Plan.

C. Increased Leak Surveys and Patrols As Interim Safety Enhancement Measures

For those pipe segments that are in Class 4, Class 3, Class 2 and Class 1 HCAs and do not have records of prior pressure testing (and are therefore included in the scope of the Implementation Plan), starting January 1, 2012, leak surveys will be conducted six times per year until the segment is tested, or replaced. PG&E also will perform leak surveys six times per year on those segments operating under 30% SMYS in Class 2 to 4 and Class 1 HCAs that are planned to be strength tested and inspected in Phase 2 (Pipeline Modernization Program Decision Tree box C3).

Starting January 1, 2012, PG&E will conduct additional patrols on the same segments of its gas transmission system discussed above. These patrols will be conducted six times annually. The Backbone Transmission system will continue to be patrolled monthly (quarterly code compliance patrols and monthly reliability patrols).

VI. REPORTING REQUIREMENTS

This section of the Implementation Plan describes PG&E's proposed Implementation Plan Report ("Report"). The focus of the Report is to provide status updates on the Implementation Plan work completed, in progress and forecast, and to note any planning approaches that provide further insight on the decision-making approaches used by PG&E to manage the Implementation Plan.

This reporting will be similar to that approved in PG&E's 2011 GT&S Rate Case (Gas Accord V) Decision 11-04-031. The report will be submitted on March 1 and September 1[9] of each year. PG&E will file this progress report together with the report approved in Decision 11-04-031. PG&E will serve the Report on the Directors of the Consumer Protection and Safety Division and Energy Division, and on the service list for those parties in this Gas Safety OIR. The Report will include the following:

- The Report will provide the progress of the physical work planned and completed, including the miles of pipe replaced, number of valves replaced, number of ILI

9/ Depending on the timing of the Commission decision on this Implementation Plan, PG&E may seek clarification of the timing of the initial report.

retrofits, number of in-line inspections, and miles of hydrotesting.

- The Report will identify and describe each Implementation Plan capital project and O&M work activity, which were planned to start during the reporting period, and the project costs associated with each project or work activity exceeding $250,000.
- For each Implementation Plan project or work activity with a cost exceeding $250,000, the Report will identify and describe each capital project, and O&M work activities, that were started, underway, or completed during the reporting period, the amount spent on each project and activity during the reporting period, the amount spent during that calendar year, and the total amount spent on each project or activity. The Report will include the start date, the completion date or anticipated completion date, and a description of the work that was performed during the reporting period. If PG&E began a project or O&M activity during the reporting period that was not previously identified as a planned project or activity in a prior Report, PG&E will provide an explanation of why that project or activity proceeded ahead of other projects or activities that were previously listed as a planned project or activity.
- The Report will describe the amount of funds budgeted at the beginning of each calendar year and over the Implementation Plan Phase 1 period (2011-2014), as well as the amount spent during the reporting period and for that calendar year, for each Major Work Category ("MWC") related to Implementation Plan for capital expenditures and for O&M activities. If PG&E does not spend the entire amount budgeted for Implementation Plan related capital projects or O&M activities, PG&E will provide an explanation in its Report. Similarly, if PG&E spends in

excess of the amount budgeted for these capital projects or O&M activities, PG&E will provide an explanation in its Report.

PG&E also proposes to give the Consumer Protection and Safety Division and the Energy Division authority to increase the Report threshold amount if they deem it appropriate by notifying the Executive Director in writing, and serving the notice on the service list in this proceeding.

VII. COST ESTIMATE AND RATEMAKING PROPOSAL

A. Introduction and Overview

This section of the Implementation Plan describes the ratemaking approach for the Implementation Plan and provides a summary of the Phase 1 costs. The Implementation Plan work is separated into two phases. Phase 1 is 2011 through 2014, and Phase 2 is 2015 and beyond. The proposed cost recovery approach is presented for Phase 1 costs below.

The key elements of the cost recovery plan include: (1) an approved forecast for capital expenditures and expenses; (2) ability to file a Tier 3 advice letter to address changed circumstances that lead to a change in scope, schedule, or costs; (3) refunds to customers for any unspent expenses at the end of Phase 1; (4) recovery of capital costs only after a project becomes operational; and (5) a shareholder cost allocation proposal. PG&E will recover the annual revenue requirements through new gas rate components included in the Customer Class Charges recovered in the end-use rates paid by core and noncore gas customers.

Phase 2 ratemaking and cost recovery will be addressed as part of a subsequent filing with the Commission.

B. Phase 1 Cost Recovery

In Decision 11-06-017, the Commission ordered PG&E to propose a cost allocation between shareholders and ratepayers.[10/] PG&E proposes that shareholders will pay for all program expenses incurred in 2011 under the Implementation Plan, as well as the capital-related revenues for 2011. Cost recovery for the final three years of Phase 1 of the Implementation Plan (2012-2014) are proposed to be recoverable in rates.

Upon approval of the Implementation Plan, the Phase 1 forecast for capital expenditures and expenses, as forecast in Chapters 3 through 7 of the accompanying testimony, is adopted. These forecasts are the project budget and are binding for the four-year period unless the Commission authorizes a mid-program modification. If changed circumstances lead to a change in the Phase 1 project scope, schedule or costs that would cause the program to exceed the Phase 1 approved forecast, PG&E may request authorization to file a Tier 3 advice letter to request cost recovery of the amounts exceeding the approved forecast. If the Commission does not approve the request for a change in the Phase 1 approved forecast or modifies the request, PG&E will adjust its work scope in Phase 1 and prioritize work within the constraints of the authorized forecast, potentially moving the work to Phase 2 of the Implementation Plan.

The Pipeline Program uses the Gas Transmission GIS for its source data. However, as discussed in Chapter 5, the system may contain errors and be missing data, which PG&E is working to resolve. Where PG&E does not have and cannot obtain sufficient and reliable data pertaining to a particular threat, the Pipeline Program makes the conservative assumption that the pipeline segment being evaluated is vulnerable to that threat. PG&E has an extensive records review underway for all gas transmission pipelines and will update the GIS database to ensure accuracy and dependability, as described in Chapter 5. Updates received from the data validation team have been, and will continue to be, incorporated into the Pipeline Program to

10/ Ordering Paragraph 10.

ensure the appropriate work plans are developed from the most accurate pipeline information possible. During preliminary project engineering, PG&E engineers will review the paper records and job files for the segment of interest, to ensure the Pipeline Program is using the most accurate information before the line is replaced, strength tested, and/or retrofitted for ILI. As additional corrections and updates are necessary, PG&E will assess and update the Pipeline Program work plan at least once a year, or more frequently as appropriate.

PG&E will establish a new balancing account to record the difference between the Phase 1 adopted forecast and recorded expenses. Should PG&E spend less than the amount authorized by the Commission for the customer-funded portion of Phase 1 (2012-2014), then a refund of the balance will be given to customers through the Gas Pipeline Safety ("GPS") rate component. Under this approach, PG&E will only spend more than the authorized amount for Phase 1 if the Commission authorizes a modification to the Phase 1 forecast through the advice letter process, as described later in this Implementation Plan.

For capital expenditures, the associated revenue requirements will be incorporated into rates beginning January 1 following the in-service date of a capital project. The revenues recorded and collected for Phase 1 would be limited to the Commission adopted target for capital spending.[11/] All pipeline segments replaced as part of the Implementation Plan will be treated as a capital expenditure.

C. Balancing Accounts

PG&E proposes to establish two new balancing accounts to track the revenue requirements for the recorded costs relative to the revenue collected.

PG&E will establish two new Gas Pipeline Safety Balancing Accounts ("GPSBA"); one

11/ The associated revenue requirements for the capital projects that become operative in 2014, the final year of Phase 1 of the Implementation Plan, will be included in rates beginning 2015.

for core gas customers and another for noncore gas customers, with separate subaccounts for each sub-component of the GPS rate component, to record the revenue requirements related to the actual cost incurred and actual revenue collected for the Implementation Plan and to provide a "true-up" to ensure that PG&E will only recover in rates costs that are actually expended on Implementation Plan program elements. Disposition of the balance of the GPSBA will be in PG&E's Annual Gas True-up ("AGT") process. The revenue recorded in the GPSBA will be collected through a new GPS rate component of the Customer Class Charge.

Each GPSBA will record, on a monthly basis, the revenue requirements associated with the actual incurred O&M and A&G expenses, and capital expenditures for in-service capital projects, as well as associated revenue collected through core and noncore GPS rates. Any resulting over-collection or under-collection will be trued up annually via PG&E's AGT advice letter.

PG&E shall establish three subaccounts in both GPS balancing accounts, each related to the Backbone, Local Transmission, and Storage revenue requirements established in this proceeding. Into each of these subaccounts, PG&E will record actual incurred O&M and A&G expenses, and capital expenditures for in-service capital projects, as well as the associated revenues collected through the subcomponents of the GPS rates. The subaccounts are described as follows:

1. Backbone Subaccount

The Backbone Subaccount records the difference between the Phase 1 Implementation Plan Backbone revenue requirement and recorded revenue collected through the GPS backbone rate component.

2. Local Transmission Subaccount

The Local Transmission Subaccount records the difference between the Phase 1

Implementation Plan Local Transmission revenue requirement and recorded revenue collected through the GPS local transmission rate component.

3. Storage Subaccount

The Storage subaccount records the difference between the Phase 1 Implementation Plan Storage revenue requirement and recorded revenue collected through the GPS storage rate component.

As mentioned above, PG&E proposes to also establish a Gas Pipeline Expense Balancing Account (GPEBA) to record the difference in aggregate between the recorded expense of the customer-funded portion of the Implementation Plan incurred during Phase 1 (2012 – 2014) and the forecast expense authorized by the Commission.

D. Natural Gas Transmission Pipeline Safety and Reliability Memorandum Account (NGTPRSMA)

PG&E requests that the Commission approve PG&E's May 5, 2011 Motion to establish the NGTPRSMA and allow PG&E to begin tracking and recording its actual revenue requirement for its 2011 and subsequent Implementation Plan costs to this memorandum account. The memorandum account would be modified to reflect PG&E's shareholder allocation proposal. This will allow PG&E to track the actual expenditures on Implementation Plan activities that will be borne by shareholders in 2011. In addition, in the event that the GPSBA is not established by January 1, 2012, the memorandum account will record and track 2012 expenditures under the Implementation Plan, which would be eligible for cost recovery. The 2012 and subsequent amounts recorded in the NGTPSRMA would be transferred to the GPEBA (actual expense) and GPSBA (in-service capital) upon the Commission's approval of the Implementation Plan.

E. Advice Letter to Adjust Approved Spend Forecasts

PG&E requests authorization to submit a Tier 3 advice letter, requesting authority for a mid-program increase in the approved costs forecasts. In its advice letter filing, PG&E will describe the work to be completed within the adopted forecasts and the additional costs required to complete the remaining Phase 1 work or other work the Commission may order PG&E to complete that is incremental to the initial Phase 1 forecast. Tier 3 advice letters require a Resolution and approval by the Commission. The public and interested parties will have an opportunity to protest and comment on such a request. In the event that the funding request made in the advice letter is not approved, or only partially approved, PG&E will be required to manage and reprioritize the remaining work scope within the approved forecast, potentially resulting in a shift of some projects to Phase 2 of the Implementation Plan.

F. Cost Estimates and Revenue Requirements

PG&E requests authorization to recover approximately $1,963.2 million of $2,183.9 million in total costs expected to be incurred from 2011 through 2014 for Phase 1 of the Implementation Plan. The total forecast expenses and capital expenditures are summarized in Tables 7-1 and 7-2, respectively.

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TABLE 7-1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF IMPLEMENTATION PLAN PHASE 1 EXPENSES
($ IN MILLIONS)

Line No.	Description	2011(a)	2012	2013	2014	Total
1	Pipeline Modernization Program	$122.7	$94.9	$87.3	$102.8	$407.7
2	Valve Automation Program	1.6	2.6	3.1	3.8	11.1
3	Pipeline Records Integration Program	55.7	88.1	32.4	7.2	183.4
4	Interim Safety Enhancement Measures	-	1.0	1.1	1.1	3.2
5	Program Management Office	1.6	3.5	3.4	3.4	11.9
6	Contingency	39.1	41.0	27.5	25.6	133.2
7	Total Expenses	$220.7	$231.1	$154.8	$143.9	$750.5

(a) The 2011 expenses will be funded by shareholders, as described in Chapter 8.

TABLE 7-2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF IMPLEMENTATION PLAN PHASE 1 CAPITAL EXPENDITURES
($ IN MILLIONS)

Line No.	Description	2011(a)	2012	2013	2014	Total
1	Pipeline Modernization Program	$32.8	$228.9	$310.5	$355.9	$928.1
2	Valve Automation Program	13.7	39.5	53.3	26.0	132.5
3	Pipeline Records Integration Program	7.4	42.3	27.2	25.7	102.6
4	Interim Safety Enhancement Measures	-	-	-	-	-
5	Program Management Office	3.0	6.6	6.7	6.6	22.9
6	Contingency	12.0	67.0	82.6	85.7	247.3
7	Total Capital Expenditures	$68.9	$384.3	$480.3	$499.9	$1,433.4

(a) The 2011 capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011, forecast at $1.4 million, will be funded by shareholders, as described in Chapter 8.

Under PG&E's proposed shareholder cost allocation proposal, the 2011 expense cost, forecast at $220.7 million, and the 2011 capital related revenues, forecast at $1.4 million,[12/] would be excluded from cost recovery and would be funded by shareholders. The adjusted costs are shown in Table 7-3.

12/ The capital related revenues are for capital projects forecast as operational in 2011. These include revenues to cover depreciation, taxes and return.

TABLE 7-3
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF IMPLEMENTATION PLAN PHASE 1 COSTS BY TYPE
ADJUSTED TO INCLUDE SHAREHOLDER COST ALLOCATION
($ IN MILLIONS)

Line No.	Description	2011(a)	2012	2013	2014	Total
1	Expenses	$220.7	$231.1	$154.8	$143.9	$750.5
2	Capital Expenditures	68.9	384.3	480.3	499.9	1,433.4
3	Total Costs	$289.6	$615.4	$635.1	$643.8	$2,183.9
4	Less: 2011 Expenses	(220.7)	-	-	-	(220.7)
5	Net Costs PG&E is Requesting for Recovery	$68.9	$615.4	$635.1	$643.8	$1,963.2

(a) The 2011 expenses, forecast at $220.7 million, and capital related costs (including depreciation, taxes and return) for capital projects forecast to be operational in 2011, forecast at $1.4 million, will be funded by shareholders, as described in Chapter 8.

Table 7-4 shows the revenue requirement to be collected from customers under PG&E's ratemaking proposal.

TABLE 7-4
PACIFIC GAS AND ELECTRIC COMPANY
2011-2014 REVENUE REQUIREMENT REQUEST
($ IN THOUSANDS)

Line No.	Revenue Requirement	2011	2012	2013	2014	Total 2011-2014
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

G. Rates

1. Cost Allocation

This section presents PG&E's cost allocation for annual Implementation Plan revenue requirements associated with Backbone Transmission, Local Transmission and Storage services.

PG&E will allocate its annual Implementation Plan Backbone Transmission-related revenue requirements to core and noncore customers based on their annual percentages of

Backbone Transmission revenue requirement responsibility[13/] established in the Gas Accord V Settlement, approved by the Commission in Decision 11-04-031.

PG&E will allocate its annual Implementation Plan Local Transmission-related revenue requirements to core and noncore customers based on their annual percentages of Local Transmission revenue requirement responsibility established in the Gas Accord V Settlement.

PG&E will allocate its target annual Implementation Plan gas Storage-related revenue requirements to core and noncore customers based on their annual percentages of gas Storage revenue requirement responsibility established in the Gas Accord V Settlement.

2. Rate Proposal

This section presents PG&E's proposal for recovery of annual Implementation Plan revenue requirements for 2012-2014. PG&E will recover its annual authorized Implementation Plan revenue requirements for 2012-2014 through new GPS rate components included in the Customer Class Charges recovered in the end-use rates paid by PG&E's core and noncore customers. The GPS rates will provide discrete Implementation Plan rate components that can be used to accurately track recovery of PG&E's annual Implementation Plan revenue requirements. The GPS rate components included in the Customer Class Charge for core and noncore customers are developed by combining the core customer classes into a single class and by combining the noncore customer classes into a single class and developing two average GPS rates—one for core and one for noncore customers. GPS rates are then calculated by dividing the total Implementation Plan Local Transmission, Backbone Transmission and gas Storage costs allocated to core and noncore customers by the total Average-Year throughput forecast adopted

13/ Noncore revenue requirement responsibility does not include the Backbone Transmission revenue requirement associated with incremental Line 401 Backbone Transmission service provided under PG&E rate Schedule G-XF - Pipeline Expansion Firm Intrastate Transportation Service.

for combined core and combined noncore customers in PG&E's Gas Accord V Settlement.

Consistent with the methodology adopted for treatment of Local Transmission costs in Gas Accord IV Decision 07-09-045 and continued in Decision 11-04-031: (1) wholesale customers pay the noncore GPS rate; and (2) annual Implementation Plan Local Transmission revenue requirements are not included in the GPS rates paid by PG&E's noncore Industrial and Electric Generation customers taking service at the Backbone Transmission level. The GPS rates paid by PG&E's noncore Industrial and Electric Generation customers taking service at the Backbone Transmission level will only include an allocation of annual Implementation Plan Backbone Transmission and gas Storage revenue requirements.[14/]

VIII. NOTICE AND SERVICE

Within twenty (20) days from the date of filing, PG&E will publish in newspapers of general circulation in each county in its service territory a notice of filing this Implementation Plan, and will mail a notice describing this Implementation Plan to the Attorney General of California, the Department of General Services, and the city and county governments within PG&E's service territory. A list of the cities and counties to which the Notice will be sent is attached to this Implementation Plan as Exhibit F. A similar notice will be included in the regular bills mailed to PG&E's customers within forty-five (45) days of the filing date of this Implementation Plan.

In addition, PG&E will serve this Implementation Plan on the service list for the Gas Safety OIR (R.11-02-019) and on the service list for PG&E's 2011 GT&S Rate Case (A.09-09-013). PG&E will serve an electronic transmittal that provides a link to the website location of

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14/ PG&E's Gas Accord III Settlement adopted by the Commission in Decision 04-12-050 provided for Backbone Transmission level end-use service for certain noncore industrial and electric generation customers. Customers qualifying for this service do not pay a Local Transmission rate component. However, they continue to be responsible for all other rate components in their end-user tariffs.

this filing and exhibits. In addition, a Notice of Availability of the Implementation Plan, testimony, work papers and exhibits will be served in accordance with Rule 1.9(c) of the Commission's Rules of Practice and Procedure.

IX. EXHIBITS

The following exhibits are appended to this Implementation Plan:

Exhibit A	Pipeline Modernization Program Project Summary
Exhibit B	Valve Automation Program Project Summary
Exhibit C	Statement of PG&E's Presently Effective Gas Rates
Exhibit D	Statement of Proposed Rate Changes
Exhibit E	Results of Operations at Proposed Rates
Exhibit F	List of cities and counties to which Notice will be sent

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X. CONCLUSION

PG&E respectfully requests that the Commission: (1) adopt PG&E's Implementation Plan as an efficient and cost-effective way to provide a pedigree of safety for each segment of PG&E's 5,786 mile gas transmission system; and (2) allow PG&E to recover in rates from 2012-2014 its costs for executing the Implementation Plan.

Respectfully submitted,

By: *_/s/ William V. Manheim_*
WILLIAM V. MANHEIM

WILLIAM V. MANHEIM
KERRY C. KLEIN
Pacific Gas and Electric Company
77 Beale Street, B30A
San Francisco, CA 94105
Telephone: (415) 973-6628
Facsimile: (415) 973-5520
E-Mail: WVM3@pge.com
KCK5@pge.com

Attorneys for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: August 26, 2011

Exhibit A

Pipeline Modernization Program Project Summary

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 1
Capital Expenditures and Expenses by Maintenance Activity Type (MAT)

MAT	MAT Description	2011	2012	2013	2014	Total	Tables 2 and 3 Reference
44A	StanPac Capital	-	609,000	-	-	**609,000**	WP 3-2, Table 2, Line 3
2H1	Imp Plan Pipe Replacement	15,489,675	197,960,965	280,150,277	339,962,087	**833,563,004**	WP 3-6, Table 2, Line 171
2H2	Imp Plan Emergency Pipe Repl	16,200,000	15,700,000	15,800,000	15,900,000	**63,599,999**	WP 3-6, Table 2, Line 176
2H4	Imp Plan ILI Pipeline Retrofit	1,125,000	14,635,000	14,599,000	-	**30,359,000**	WP 3-6, Table 2, Line 184
	Total Capital Expenditures	**32,814,675**	**228,904,965**	**310,549,277**	**355,862,087**	**928,131,004**	WP 3-6, Table 2, Line 186
34A	StanPac Expense	4,115,000	-	-	-	**4,115,000**	WP 3-753, Table 3, Line 3
KE1	Imp Plan Pipe Pressure Test	116,943,156	93,728,943	84,512,978	93,860,931	**389,046,008**	WP 3-757, Table 3, Line 168
KE3	Imp Plan Pipeline ILI	-	-	1,725,000	7,866,000	**9,591,000**	WP 3-757, Table 3, Line 178
KEX	Imp Plan Pipeline Other	1,600,000	1,150,000	1,055,000	1,085,000	**4,890,000**	WP 3-757, Table 3, Line 183
	Total Expenses	**122,658,156**	**94,878,943**	**87,292,978**	**102,811,931**	**407,642,008**	WP 3-757, Table 3, Line 185
	Total Pipeline Modernization Costs	**155,472,830**	**323,783,908**	**397,842,255**	**458,674,018**	**1,335,773,011**	

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
1	97000512	24254	SP-3 REPL 0.04mi MP 167.28-198.48 PH1	44A	7/1/2012	-	235,000	-	-	**235,000**	WP 3-7	WP 3-579
2	97000661	24909	SP4Z REPL 0.07mi MP 8.21-8.29 PH1	44A	7/1/2012	-	374,000	-	-	**374,000**	WP 3-11	WP 3-580
3			**Total MAT 44A - StanPac Capital**			**-**	**609,000**	**-**	**-**	**609,000**		
4												
5	30842206	23796	L-021C REPL 0.75MI MP 31.84-35.05 PH1	2H1	12/1/2014	-	-	496,000	4,464,000	**4,960,000**	WP 3-14	WP 3-581
6	30843897	24052	L-021D REPL 2.26MI MP 18.96-24.49 PH1	2H1	12/1/2013	-	1,453,000	13,076,000	-	**14,529,000**	WP 3-17	WP 3-582
7	30842239	23727	L-021F REPL 4.24MI MP 0.00-21.16 PH1	2H1	12/1/2013	1,755	2,043,245	18,366,000	-	**20,411,000**	WP 3-20	WP 3-583
8	30843899	24055	L-021H REPL 0.61MI MP 0.00-6.42 PH1	2H1	12/1/2014	-	-	239,000	2,148,000	**2,387,000**	WP 3-24	WP 3-584
9	30842207	23790	L-050A REPL 0.24MI MP 16.81-17.03 PH1	2H1	12/1/2014	-	-	139,000	1,255,000	**1,394,000**	WP 3-28	WP 3-585
10	30842247	23758	L-050A-1 REPL 0.09MI MP 0.66-2.32 PH1	2H1	7/1/2012	-	603,000	-	-	**603,000**	WP 3-31	WP 3-586
11	30843924	24059	L-057A REPL 7.60MI MP 8.97-16.68 PH1	2H1	12/1/2013	150,000	2,511,000	25,444,000	-	**28,105,000**	WP 3-34	WP 3-587
12	30843925	24060	L-057A-MT REPL 0.03MI MP 0.56-0.58 PH1	2H1	7/1/2014	-	-	-	203,000	**203,000**	WP 3-37	WP 3-588
13	30842170	23799	L-057B REPL 0.01MI MP 10.32-10.32 PH1	2H1	7/1/2012	-	1	-	-	**1**	WP 3-40	WP 3-589
14	30842171	23818	L-101 REPL 0.02MI MP 9.28-9.30 PH1	2H1	7/1/2012	-	1	-	-	**1**	WP 3-43	WP 3-590
15	30842130	23728	L-103 REPL 7.75MI MP 5.68-23.56 PH1	2H1	12/1/2014	150,000	2,649,000	-	26,008,000	**28,807,000**	WP 3-46	WP 3-591
16	30865387	24897	L-105A-1 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2012	-	162,000	-	-	**162,000**	WP 3-49	WP 3-592
17	30865388	24898	L-105N-3 REPL 0.03MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	185,000	-	**185,000**	WP 3-52	WP 3-593
18	30865389	24899	L-105N-5 REPL 0.10MI MP 36.39-36.47 PH1	2H1	7/1/2012	-	507,000	-	-	**507,000**	WP 3-55	WP 3-594
19	30843913	24077	L-108_1 REPL 1.06MI MP 37.14-38.17 PH1	2H1	12/1/2014	25,000	-	328,000	3,181,000	**3,534,000**	WP 3-58	WP 3-595
20	30842211	23815	L-108_2 REPL 2.58MI MP 48.20-50.69 PH1	2H1	12/1/2014	25,000	-	1,016,000	9,116,000	**10,157,000**	WP 3-61	WP 3-596
21	30865390	24900	L-108_3 REPL 3.06MI MP 63.50-73.58 PH1	2H1	12/1/2013	25,000	1,273,000	11,434,000	-	**12,732,000**	WP 3-64	WP 3-597
22	P.03741	23365	L-109_1 REPL 3.70MI MP 3.41-9.89 PH1	2H1	12/1/2012	5,300,000	27,315,000	-	-	**32,615,000**	WP 3-67	WP 3-598
23	30842248	23724	L-109_2 REPL 4.65MI MP 0.49-16.93 PH1	2H1	12/1/2013	150,000	3,156,000	34,070,000	-	**37,376,000**	WP 3-70	WP 3-599
24	30842212	23704	L-109_3 REPL 6.06MI MP 16.93-24.00 PH1	2H1	12/1/2014	150,000	350,000	4,431,000	43,470,000	**48,401,000**	WP 3-74	WP 3-600
25	30842214	23692	L-109_4 REPL 6.84MI MP 24.84-33.26 PH1	2H1	12/1/2014	150,000	350,000	3,459,000	35,626,000	**39,585,000**	WP 3-78	WP 3-601
26	30842224	23795	L-109_5 REPL 0.13MI MP 34.39-45.84 PH1	2H1	12/1/2012	132,000	1,190,000	-	-	**1,322,000**	WP 3-81	WP 3-602
27	30842215	23832	L-111A REPL 6.61MI MP 19.30-27.53 PH1	2H1	12/1/2012	1,887,000	28,532,000	-	-	**30,419,000**	WP 3-84	WP 3-603
28	30843920	24084	L-114_1 REPL 0.06MI MP 16.51-16.57 PH1	2H1	7/1/2012	-	285,000	-	-	**285,000**	WP 3-87	WP 3-604
29	30841472	23688	L-114_2 REPL 7.50MI MP 9.03-28.98 PH1	2H1	12/1/2012	616,000	35,431,000	-	-	**36,047,000**	WP 3-90	WP 3-605
30	30842216	23888	L-116 REPL 0.04MI MP 0.00-0.03 PH1	2H1	7/1/2013	-	-	112,000	-	**112,000**	WP 3-95	WP 3-606
31	30865391	24901	L-118-1 REPL 0.02MI MP 0.01-0.03 PH1	2H1	7/1/2013	-	-	236,000	-	**236,000**	WP 3-98	WP 3-607
32	30842245	23743	L-118A REPL 6.87MI MP 5.62-12.55 PH1	2H1	12/1/2013	150,000	1,895,000	18,296,000	-	**20,341,000**	WP 3-101	WP 3-608
33	30842164	23791	L-119B REPL 0.29MI MP 8.96-9.22 PH1	2H1	12/1/2013	-	104,000	939,000	-	**1,043,000**	WP 3-104	WP 3-609
34	30865392	24902	L-119B-1 REPL 0.03MI MP 0.00-0.03 PH1	2H1	7/1/2012	-	129,000	-	-	**129,000**	WP 3-107	WP 3-610
35	30842218	23822	L-123 REPL 4.17MI MP 0.00-7.51 PH1	2H1	12/1/2014	25,000	-	1,005,000	9,023,000	**10,053,000**	WP 3-110	WP 3-611
36	30843915	24079	L-124A REPL 4.32MI MP 20.63-26.27 PH1	2H1	12/1/2013	-	1,698,000	15,280,000	-	**16,978,000**	WP 3-113	WP 3-612
37	30842219	23793	L-125 REPL 1.31MI MP 0.00-0.00 PH1	2H1	12/1/2014	277	-	451,723	4,065,000	**4,517,000**	WP 3-116	WP 3-613
38	30841610	23677	L-130 REPL 0.48MI MP 0.00-0.50 PH1	2H1	12/1/2013	-	385,000	3,463,000	-	**3,848,000**	WP 3-119	WP 3-614
39	30841473	23694	L-131_1 REPL 1.70MI MP 42.35-57.47 PH1	2H1	12/1/2012	1,198,000	10,485,000	-	-	**11,683,000**	WP 3-122	WP 3-615
40	30841475	23746	L-131_2 REPL 0.29MI MP 8.15-43.49 PH1	2H1	12/1/2012	135,000	1,212,000	-	-	**1,347,000**	WP 3-126	WP 3-616

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
41	30865393	24903	L-131Y REPL 0.01MI MP 0.02-0.54 PH1	2H1	7/1/2012	-	79,000	-	-	**79,000**	WP 3-129	WP 3-617
42	30865394	24904	L-132B REPL 0.01MI MP 0.01-0.01 PH1	2H1	7/1/2013	-	-	70,000	-	**70,000**	WP 3-132	WP 3-618
43	30843909	24072	L-134A REPL 0.18MI MP 31.17-31.34 PH1	2H1	12/1/2014	-	-	-	641,000	**641,000**	WP 3-135	WP 3-619
44	30842161	23765	L-136 REPL 0.01MI MP 9.69-9.70 PH1	2H1	7/1/2014	-	-	-	61,000	**61,000**	WP 3-138	WP 3-620
45	30842223	23825	L-138 REPL 6.51MI MP 38.58-45.09 PH1	2H1	12/1/2012	1,650,000	29,838,000	-	-	**31,488,000**	WP 3-141	WP 3-621
46	30843888	24041	L-138C REPL 0.01MI MP 43.58-43.59 PH1	2H1	7/1/2012	-	134,000	-	-	**134,000**	WP 3-145	WP 3-622
47	30843889	24042	L-138D REPL 0.01MI MP 45.10-45.10 PH1	2H1	7/1/2014	-	-	-	54,000	**54,000**	WP 3-148	WP 3-623
48	30841613	23816	L-142S REPL 1.06MI MP 0.0027-6.35 PH1	2H1	12/1/2012	373,000	3,354,000	-	-	**3,727,000**	WP 3-151	WP 3-624
49	30842131	23735	L-151-1 REPL 0.02MI MP 10.44-10.45 PH1	2H1	7/1/2014	-	-	-	100,000	**100,000**	WP 3-154	WP 3-625
50	30865395	24905	L-153-6 REPL 0.03MI MP 0.00-0.03 PH1	2H1	7/1/2012	-	181,000	-	-	**181,000**	WP 3-157	WP 3-626
51	30842225	23731	L-162A REPL 1.12MI MP 6.62-7.72 PH1	2H1	12/1/2014	-	-	541,000	4,873,000	**5,414,000**	WP 3-160	WP 3-627
52	30842227	23845	L-167 REPL 10.72MI MP 22.56-34.52 PH1	2H1	12/1/2013	22,967	2,660,033	23,898,000	-	**26,581,000**	WP 3-163	WP 3-628
53	30842228	23797	L-167-1 REPL 2.09MI MP 4.46-6.55 PH1	2H1	12/1/2012	615,000	5,539,000	-	-	**6,154,000**	WP 3-166	WP 3-629
54	30842229	23926	L-172A REPL 0.04MI MP 69.79-79.13 PH1	2H1	7/1/2012	-	162,000	-	-	**162,000**	WP 3-169	WP 3-630
55	30865396	24906	L-172A-1 REPL 0.19MI MP 78.53-78.72 PH1	2H1	12/1/2013	-	-	702,000	-	**702,000**	WP 3-172	WP 3-631
56	30842236	23800	L-172A-17-3 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	26,000	-	**26,000**	WP 3-175	WP 3-632
57	30842230	23824	L-173 REPL 0.01MI MP 5.51-5.51 PH1	2H1	7/1/2013	-	-	91,000	-	**91,000**	WP 3-179	WP 3-633
58	30842232	23789	L-177A REPL 3.27MI MP 25.46-173.89 PH1	2H1	12/1/2014	-	-	777,000	6,997,000	**7,774,000**	WP 3-182	WP 3-634
59	30843916	24080	L-177E REPL 1.04MI MP 0.19-1.23 PH1	2H1	12/1/2014	-	-	189,000	1,696,000	**1,885,000**	WP 3-185	WP 3-635
60	30842234	23772	L-181A REPL 1.73MI MP 15.31-16.81 PH1	2H1	12/1/2012	456,000	4,105,000	-	-	**4,561,000**	WP 3-188	WP 3-636
61	30842233	23782	L-181A-10 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	65,000	**65,000**	WP 3-191	WP 3-637
62	30842235	23773	L-181B REPL 0.36MI MP 2.17-10.32 PH1	2H1	12/1/2012	140,000	1,256,000	-	-	**1,396,000**	WP 3-194	WP 3-638
63	30843906	24067	L-185 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	53,000	**53,000**	WP 3-197	WP 3-639
64	30841618	23748	L-191 REPL 2.20MI MP 0.07-6.47 PH1	2H1	12/1/2013	25,000	2,049,000	18,171,000	-	**20,245,000**	WP 3-200	WP 3-640
65	30865397	24907	L-191B REPL 0.01MI MP 1.63-1.64 PH1	2H1	7/1/2014	-	-	-	68,000	**68,000**	WP 3-203	WP 3-641
66	30841612	23702	L-196A REPL 1.52MI MP 11.93-13.45 PH1	2H1	12/1/2013	-	263,000	2,362,000	-	**2,625,000**	WP 3-206	WP 3-642
67	30843898	24053	L-200A-2 REPL 0.51MI MP 0.48-1.00 PH1	2H1	12/1/2013	-	112,000	1,003,000	-	**1,115,000**	WP 3-209	WP 3-643
68	30842237	23698	L-210A REPL 2.28MI MP 19.51-25.62 PH1	2H1	12/1/2012	778,000	6,998,000	-	-	**7,776,000**	WP 3-212	WP 3-644
69	30842240	23867	L-220 REPL 5.77MI MP 18.73-34.92 PH1	2H1	12/1/2013	-	2,396,000	21,388,000	-	**23,784,000**	WP 3-215	WP 3-645
70	30841463	23484	L-300B REPL 0.36MI MP 160.88-248.97 PH1	2H1	12/1/2014	-	-	188,000	1,689,000	**1,877,000**	WP 3-219	WP 3-646
71	30842242	23770	L-301A REPL 0.07MI MP 0.00-17.69 PH1	2H1	7/1/2012	10,776	186,224	-	-	**197,000**	WP 3-222	WP 3-647
72	30842243	23777	L-301B REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	76,000	**76,000**	WP 3-225	WP 3-648
73	30842244	23792	L-301C REPL 0.01MI MP 17.26-17.26 PH1	2H1	7/1/2012	-	109,000	-	-	**109,000**	WP 3-228	WP 3-649
74	30842246	23779	L-301G REPL 0.01MI MP 2.34-2.34 PH1	2H1	7/1/2012	-	1	-	-	**1**	WP 3-231	WP 3-650
75	30843887	24040	L-306 REPL 0.03MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	128,000	**128,000**	WP 3-234	WP 3-651
76	30842250	23775	L-310 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	60,000	**60,000**	WP 3-237	WP 3-652
77	30841464	23798	L-314 REPL 0.57MI MP 20.31-20.91 PH1	2H1	12/1/2014	-	-	104,000	932,000	**1,036,000**	WP 3-240	WP 3-653
78	30842125	23742	L-314A REPL 0.08MI MP 0.15-0.24 PH1	2H1	7/1/2013	-	-	190,000	-	**190,000**	WP 3-243	WP 3-654
79	30865398	24908	L-331B-1 REPL 0.02MI MP 0.74-0.76 PH1	2H1	7/1/2014	-	-	-	1	**1**	WP 3-246	WP 3-655
80	30842122	23831	L-400 REPL 0.06MI MP 115.31-115.37 PH1	2H1	7/1/2014	-	-	-	388,000	**388,000**	WP 3-249	WP 3-656

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
81	30841476	23736	DFM-0107-01 REPL 0.24MI MP 0.00-0.24 PH1	2H1	12/1/2014	-	-	122,000	1,100,000	**1,222,000**	WP 3-254	WP 3-657
82	30842180	23774	DFM-0107-02 REPL 0.02MI MP 0.00-0.01 PH1	2H1	7/1/2014	-	-	-	102,000	**102,000**	WP 3-257	WP 3-658
83	30842132	23739	DFM-0205-01 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	65,000	**65,000**	WP 3-260	WP 3-659
84	30842128	23693	DFM-0223-03 REPL 0.07MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	131,000	**131,000**	WP 3-263	WP 3-660
85	30842163	23781	DFM-0401-10 REPL 0.01MI MP 0.00-0.01 PH1	2H1	7/1/2014	-	-	-	80,000	**80,000**	WP 3-266	WP 3-661
86	30841720	23759	DFM-0403-10 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	57,000	**57,000**	WP 3-269	WP 3-662
87	30842168	23849	DFM-0404-11 REPL 0.04MI MP 0.00-0.04 PH1	2H1	7/1/2013	-	-	230,000	-	**230,000**	WP 3-272	WP 3-663
88	30842175	23786	DFM-0405-01 REPL 8.04MI MP 2.04-12.36 PH1	2H1	12/1/2013	-	3,571,000	32,100,000	-	**35,671,000**	WP 3-275	WP 3-664
89	30842129	23729	DFM-0405-16 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	57,000	**57,000**	WP 3-279	WP 3-665
90	30842176	23811	DFM-0603-01 REPL 0.58MI MP 0.00-0.57 PH1	2H1	12/1/2013	-	183,000	1,528,000	-	**1,711,000**	WP 3-282	WP 3-666
91	30843921	24085	DFM-0604-06 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	1,242	-	-	55,758	**57,000**	WP 3-286	WP 3-667
92	30842189	23780	DFM-0604-16 REPL 0.50MI MP 0.00-0.500 PH1	2H1	12/1/2013	-	113,000	1,021,000	-	**1,134,000**	WP 3-289	WP 3-668
93	30842196	23760	DFM-0611-08 REPL 0.06MI MP 0.00-0.06 PH1	2H1	7/1/2013	446	-	336,554	-	**337,000**	WP 3-292	WP 3-669
94	30842203	23725	DFM-0614-10 REPL 0.09MI MP 0.00-0.00 PH1	2H1	7/1/2014	1,312	-	-	511,688	**513,000**	WP 3-295	WP 3-670
95	30842238	23707	DFM-0617-06 REPL 0.01MI MP 10.63-10.63 PH1	2H1	7/1/2014	-	-	-	110,000	**110,000**	WP 3-298	WP 3-671
96	30842194	23716	DFM-0619-05 REPL 0.08MI MP 1.29-1.38 PH1	2H1	7/1/2014	-	-	-	731,000	**731,000**	WP 3-301	WP 3-672
97	30842177	23930	DFM-0627-01 REPL 0.02MI MP 0.00-0.02 PH1	2H1	7/1/2013	-	-	189,000	-	**189,000**	WP 3-304	WP 3-673
98	30842199	23855	DFM-0630-01 REPL 0.14MI MP 0.00-10.55 PH1	2H1	12/1/2014	-	-	29,000	265,000	**294,000**	WP 3-307	WP 3-674
99	30865351	24882	DFM-0630-06 REPL 0.10MI MP 0.00-0.10 PH1	2H1	12/1/2014	-	-	36,000	320,000	**356,000**	WP 3-310	WP 3-675
100	30865352	24883	DFM-0804-01 REPL 0.01MI MP 0.21-1.16 PH1	2H1	7/1/2012	-	84,000	-	-	**84,000**	WP 3-313	WP 3-676
101	30865353	24884	DFM-0804-03 REPL 0.02MI MP 0.00-0.02 PH1	2H1	7/1/2014	-	-	-	135,000	**135,000**	WP 3-316	WP 3-677
102	30843917	24081	DFM-0809-01 REPL 0.03MI MP 0.00-0.03 PH1	2H1	7/1/2014	-	-	-	158,000	**158,000**	WP 3-319	WP 3-678
103	30842204	23722	DFM-0810-01 REPL 0.03MI MP 0.00-0.03 PH1	2H1	7/1/2014	-	-	-	80,000	**80,000**	WP 3-322	WP 3-679
104	30865355	24885	DFM-0837-01 REPL 0.03MI MP 1.52-1.54 PH1	2H1	7/1/2014	-	-	-	133,000	**133,000**	WP 3-325	WP 3-680
105	30865356	24886	DFM-1013-02 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	62,000	**62,000**	WP 3-328	WP 3-681
106	30865357	24887	DFM-1017-01 REPL 0.01MI MP 0.01-0.01 PH1	2H1	7/1/2013	-	-	72,000	-	**72,000**	WP 3-331	WP 3-682
107	30842178	23807	DFM-1020-01 REPL 2.69MI MP 0.00-2.69 PH1	2H1	12/1/2014	25,000	-	797,000	7,146,000	**7,968,000**	WP 3-334	WP 3-683
108	30842179	23810	DFM-1024-02 REPL 0.02MI MP 0.00-0.02 PH1	2H1	7/1/2014	-	-	-	108,000	**108,000**	WP 3-337	WP 3-684
109	30841611	23686	DFM-1202-12 REPL 0.01MI MP 1.90-1.92 PH1	2H1	7/1/2013	-	-	76,000	-	**76,000**	WP 3-340	WP 3-685
110	30842181	23685	DFM-1202-15 REPL 0.02MI MP 0.00-0.02 PH1	2H1	7/1/2012	-	101,000	-	-	**101,000**	WP 3-343	WP 3-686
111	30842127	23711	DFM-1202-16 REPL 0.08MI MP 0.00-0.08 PH1	2H1	7/1/2013	-	-	342,000	-	**342,000**	WP 3-346	WP 3-687
112	30842182	23828	DFM-1209-01 REPL 0.34MI MP 4.29-4.64 PH1	2H1	12/1/2014	-	-	116,000	1,044,000	**1,160,000**	WP 3-349	WP 3-688
113	30842221	23717	DFM-1209-05 REPL 0.03MI MP 4.99-5.02 PH1	2H1	7/1/2014	1,360	-	-	222,640	**224,000**	WP 3-352	WP 3-689
114	30842183	23821	DFM-1213-01 REPL 0.26MI MP 0.55-3.51 PH1	2H1	7/1/2014	-	-	-	632,000	**632,000**	WP 3-355	WP 3-690
115	30842220	23726	DFM-1220-01 REPL 0.01MI MP 0.86-0.86 PH1	2H1	7/1/2013	-	-	63,000	-	**63,000**	WP 3-358	WP 3-691
116	30865358	24888	DFM-1302-01 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	133,000	-	**133,000**	WP 3-361	WP 3-692
117	30842172	23830	DFM-1302-02 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	82,000	-	**82,000**	WP 3-364	WP 3-693
118	30842185	23802	DFM-1306-01 REPL 0.04MI MP 1.48-4.19 PH1	2H1	7/1/2013	-	-	325,000	-	**325,000**	WP 3-367	WP 3-694
119	30865359	24889	DFM-1306-06 REPL 0.02MI MP 0.00-0.01 PH1	2H1	7/1/2013	-	-	179,000	-	**179,000**	WP 3-370	WP 3-695
120	30842186	23805	DFM-1307-06 REPL 0.03MI MP 0.00-0.00 PH1	2H1	7/1/2014	-	-	-	160,000	**160,000**	WP 3-373	WP 3-696

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
121	30842222	23751	DFM-1406-01 REPL 0.01MI MP 0.00-0.01 PH1	2H1	7/1/2013	-	-	67,000	-	**67,000**	WP 3-376	WP 3-697
122	30842187	23862	DFM-1502-08 REPL 0.53MI MP 0.00-0.52 PH1	2H1	12/1/2014	-	-	271,000	2,437,000	**2,708,000**	WP 3-379	WP 3-698
123	30842188	23875	DFM-1503-01 REPL 0.93MI MP 0.00-0.92 PH1	2H1	12/1/2014	-	-	325,000	2,923,000	**3,248,000**	WP 3-382	WP 3-699
124	30842190	23783	DFM-1509-01 REPL 0.33MI MP 0.00-0.33 PH1	2H1	12/1/2014	-	-	63,000	470,000	**533,000**	WP 3-385	WP 3-700
125	30842249	23778	DFM-1509-04 REPL 0.01MI MP 0.78-0.78 PH1	2H1	7/1/2012	-	51,000	-	-	**51,000**	WP 3-388	WP 3-701
126	30842192	23733	DFM-1603-03 REPL 0.01MI MP 0.48-0.49 PH1	2H1	7/1/2014	-	-	-	96,000	**96,000**	WP 3-391	WP 3-702
127	30865380	24890	DFM-1607-01 REPL 1.62MI MP 0.00-1.62 PH1	2H1	12/1/2014	-	-	873,000	7,858,000	**8,731,000**	WP 3-394	WP 3-703
128	30842193	23697	DFM-1614-08 REPL 0.44MI MP 0.56-1.00 PH1	2H1	12/1/2014	-	-	165,000	1,487,000	**1,652,000**	WP 3-397	WP 3-704
129	30842191	23827	DFM-1615-07 REPL 0.01MI MP 0.00-0.01 PH1	2H1	7/1/2013	-	-	77,000	-	**77,000**	WP 3-400	WP 3-705
130	30842195	23682	DFM-1617-01 REPL 0.44MI MP 0.82-1.26 PH1	2H1	12/1/2014	-	-	165,000	1,484,000	**1,649,000**	WP 3-403	WP 3-706
131	30865381	24891	DFM-1805-01 REPL 0.03MI MP 0.00-0.03 PH1	2H1	7/1/2013	-	-	98,000	-	**98,000**	WP 3-406	WP 3-707
132	30841468	23762	DFM-1813-02 REPL 0.07MI MP 1.00-16.40 PH1	2H1	7/1/2012	-	161,000	-	-	**161,000**	WP 3-409	WP 3-708
133	30842241	23684	DFM-1813-06 REPL 0.02MI MP 0.00-0.02 PH1	2H1	7/1/2014	-	-	-	85,000	**85,000**	WP 3-412	WP 3-709
134	30842226	23769	DFM-1815-02 REPL 0.72MI MP 18.76-19.48 PH1	2H1	12/1/2014	-	-	326,000	2,938,000	**3,264,000**	WP 3-415	WP 3-710
135	30842184	23801	DFM-1815-15 REPL 0.01MI MP 1.38-1.39 PH1	2H1	7/1/2013	-	-	74,000	-	**74,000**	WP 3-418	WP 3-711
136	30842138	23784	DFM-1816-20 REPL 0.01MI MP 0.00-0.01 PH1	2H1	7/1/2014	-	-	-	89,000	**89,000**	WP 3-421	WP 3-712
137	30842197	23761	DFM-1817-01 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	74,000	-	**74,000**	WP 3-424	WP 3-713
138	30842198	23766	DFM-1818-01 REPL 0.13MI MP 0.00-0.60 PH1	2H1	12/1/2014	-	-	-	276,000	**276,000**	WP 3-427	WP 3-714
139	30865382	24892	DFM-1880-08 REPL 0.02MI MP 0.00-0.02 PH1	2H1	7/1/2014	-	-	-	132,000	**132,000**	WP 3-430	WP 3-715
140	30841609	23806	DFM-2410-01 REPL 0.02MI MP 0.00-0.03 PH1	2H1	7/1/2014	-	-	-	94,000	**94,000**	WP 3-433	WP 3-716
141	30865383	24893	DFM-2412-01 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	52,000	-	**52,000**	WP 3-436	WP 3-717
142	30865384	24894	DFM-3002-01 REPL 0.02MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	100,000	-	**100,000**	WP 3-439	WP 3-718
143	30865385	24895	DFM-3008-01 REPL 0.03MI MP 7.99-8.02 PH1	2H1	7/1/2013	-	-	182,000	-	**182,000**	WP 3-442	WP 3-719
144	30841615	23699	DFM-3022-01 REPL 0.01MI MP 0.00-0.00 PH1	2H1	7/1/2013	-	-	51,000	-	**51,000**	WP 3-445	WP 3-720
145	30842200	23695	DFM-7219-01 REPL 3.73MI MP 0.00-3.73 PH1	2H1	12/1/2014	-	-	952,000	8,569,000	**9,521,000**	WP 3-449	WP 3-721
146	30842137	23763	DFM-7220-01 REPL 0.02MI MP 15.71-15.74 PH1	2H1	7/1/2014	-	-	-	87,000	**87,000**	WP 3-452	WP 3-722
147	30842201	23720	DFM-7221-10 REPL 0.14MI MP 15.98-16.13 PH1	2H1	12/1/2012	540	488,460	-	-	**489,000**	WP 3-455	WP 3-723
148	30841616	23710	DFM-7221-15 REPL 1.34MI MP 0.04-1.51 PH1	2H1	12/1/2012	713,000	6,413,000	-	-	**7,126,000**	WP 3-458	WP 3-724
149	30842202	23701	DFM-7225-02 REPL 2.15MI MP 0.00-2.42 PH1	2H1	12/1/2014	-	-	1,149,000	10,340,000	**11,489,000**	WP 3-461	WP 3-725
150	30841614	23617	DFM-7226-02 REPL 1.37MI MP 0.34-3.26 PH1	2H1	12/1/2012	406,000	3,656,000	-	-	**4,062,000**	WP 3-464	WP 3-726
151	30865386	24896	DFM-8832-01 REPL 0.02MI MP 0.00-0.01 PH1	2H1	7/1/2013	-	-	79,000	-	**79,000**	WP 3-467	WP 3-727
152	30842139	23750	TAPS-REPL CC PH1	2H1	12/1/2014	-	-	1,682,000	14,676,000	**16,358,000**	WP 3-470	WP 3-728
153	30842135	23753	TAPS-REPL DA PH1	2H1	12/1/2014	-	-	710,000	6,326,000	**7,036,000**	WP 3-476	WP 3-729
154	30841617	23741	TAPS-REPL DI PH1	2H1	12/1/2014	-	-	661,000	5,872,000	**6,533,000**	WP 3-481	WP 3-730
155	30842136	23757	TAPS-REPL EB PH1	2H1	7/1/2014	-	-	-	458,000	**458,000**	WP 3-486	WP 3-731
156	30842123	23690	TAPS-REPL FR PH1	2H1	12/1/2014	-	-	593,000	5,335,000	**5,928,000**	WP 3-490	WP 3-732
157	30842165	23794	TAPS-REPL HB PH1	2H1	12/1/2014	-	-	561,000	5,052,000	**5,613,000**	WP 3-495	WP 3-733
158	30841139	23616	TAPS-REPL KE PH1	2H1	12/1/2014	-	-	737,000	6,392,000	**7,129,000**	WP 3-499	WP 3-734
159	30842173	23923	TAPS-REPL LP PH1	2H1	7/1/2014	-	-	-	304,000	**304,000**	WP 3-504	WP 3-735
160	30842205	23749	TAPS-REPL MI PH1	2H1	12/1/2014	-	-	1,053,000	9,359,000	**10,412,000**	WP 3-507	WP 3-736

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

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161	30842124	23718	TAPS-REPL NB PH1	2H1	12/1/2014	-	-	246,000	2,165,000	**2,411,000**	WP 3-509	WP 3-737
162	30842162	23776	TAPS-REPL NV PH1	2H1	12/1/2014	-	-	1,024,000	9,063,000	**10,087,000**	WP 3-514	WP 3-738
163	30842133	23740	TAPS-REPL PN PH1	2H1	12/1/2014	-	-	1,128,000	10,087,000	**11,215,000**	WP 3-518	WP 3-739
164	30842174	23928	TAPS-REPL SA PH1	2H1	12/1/2014	-	-	1,490,000	11,621,000	**13,111,000**	WP 3-524	WP 3-740
165	30842166	23817	TAPS-REPL SF PH1	2H1	12/1/2014	-	-	257,000	2,309,000	**2,566,000**	WP 3-530	WP 3-741
166	30842169	23787	TAPS-REPL SI PH1	2H1	12/1/2014	-	-	497,000	2,974,000	**3,471,000**	WP 3-533	WP 3-742
167	30842126	23689	TAPS-REPL SJ PH1	2H1	12/1/2014	-	-	847,000	7,606,000	**8,453,000**	WP 3-538	WP 3-743
168	30842134	23744	TAPS-REPL SO PH1	2H1	12/1/2014	-	-	139,000	1,251,000	**1,390,000**	WP 3-543	WP 3-744
169	30841474	23706	TAPS-REPL ST PH1	2H1	12/1/2014	-	-	1,878,000	16,824,000	**18,702,000**	WP 3-546	WP 3-745
170	30842160	23785	TAPS-REPL YO PH1	2H1	12/1/2014	-	-	1,562,000	13,017,000	**14,579,000**	WP 3-551	WP 3-746
171			**Total MAT 2H1 - Imp Plan Pipe Replacement**			**15,489,675**	**197,960,965**	**280,150,277**	**339,962,087**	**833,563,004**		
172												
173	30843926	24030	Emergency Pipe Replacement	2H2	12/31/2014	2,000,000	2,000,000	2,000,000	2,000,000	**8,000,000**	WP 3-557	n/a
174	30846247	24158	Strength Test-Capital Valves and Testheads	2H2	12/31/2014	6,700,000	3,700,000	3,800,000	3,900,000	**18,100,000**	WP 3-558	n/a
175	30866501	25002	Post StrengthTest Emergency Replacements	2H2	12/31/2014	7,500,000	10,000,000	10,000,000	10,000,000	**37,500,000**	WP 3-559	n/a
176			**Total MAT 2H2 - Imp Plan Emergency Pipe Repl**			**16,200,000**	**15,700,000**	**15,800,000**	**15,900,000**	**63,599,999**		
177												
178	30847124	24009	L-131 MP 50.5-57.4 UPGRADE PH-1	2H4	11/1/2012	150,000	1,500,000	357,000	-	**2,007,000**	WP 3-560	WP 3-747
179	30846928	24025	L-132 MP 31.9-38.4 UPGRADE PH-1	2H4	11/1/2012	75,000	1,500,000	462,000	-	**2,037,000**	WP 3-563	WP 3-748
180	30846926	24023	L-300A MP 299-352 UPGRADE PH-1	2H4	11/1/2013	150,000	1,000,000	6,935,000	-	**8,085,000**	WP 3-566	WP 3-749
181	30846925	24021	L-300A MP 353-391 UPGRADE PH-1	2H4	11/1/2012	300,000	4,534,000	-	-	**4,834,000**	WP 3-570	WP 3-750
182	30846924	24017	L-300B MP 299-353 UPGRADE PH-1	2H4	11/1/2013	150,000	1,000,000	6,845,000	-	**7,995,000**	WP 3-573	WP 3-751
183	30846923	24012	L-300B MP 353-390 UPGRADE PH-1	2H4	11/1/2012	300,000	5,101,000	-	-	**5,401,000**	WP 3-576	WP 3-752
184			**Total MAT 2H4 - Imp Plan ILI Pipeline Retrofit**			**1,125,000**	**14,635,000**	**14,599,000**	**-**	**30,359,000**		
185												
186			**Total Pipeline Modernization Capital Projects**			**32,814,675**	**228,904,965**	**310,549,277**	**355,862,087**	**928,131,004**		

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 3
Expenses by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
1	97000510	24160	SP3 TEST 0.49MI MP 180.91-181.40 PH1	34A	12/1/2011	1,098,000	-	-	-	**1,098,000**	WP 3-758	WP 3-1311
2	9715461	24162	SP5 TEST 3.87MI MP 0.00-3.87 PH1	34A	12/1/2011	3,017,000	-	-	-	**3,017,000**	WP 3-761	WP 3-1312
3			**Total MAT 34A - StanPac Expense**			**4,115,000**	**-**	**-**	**-**	**4,115,000**		
4												
5	41482857	24202	L-002 TEST 4.48MI MP 75.90-122.00 PH1	KE1	12/1/2014	-	-	-	3,673,000	**3,673,000**	WP 3-764	WP 3-1313
6	41482922	24210	L-021A_1 TEST 0.09MI MP 24.49-24.58 PH1	KE1	7/1/2012	-	1,021,000	-	-	**1,021,000**	WP 3-767	WP 3-1314
7	41473973	23881	L-021A_2 TEST 0.36MI MP 16.96-17.31 PH1	KE1	7/1/2012	-	1	-	-	**1**	WP 3-770	WP 3-1315
8	41474090	23532	L-021B TEST 18.93MI MP 0.00-18.64 PH1	KE1	12/1/2013	-	-	6,348,000	-	**6,348,000**	WP 3-773	WP 3-1316
9	41474091	23533	L-021C TEST 7.10MI MP 35.05-51.41 PH1	KE1	12/1/2012	-	2,236,000	-	-	**2,236,000**	WP 3-776	WP 3-1317
10	41482921	24208	L-021D TEST 0.28MI MP 24.67-24.95 PH1	KE1	7/1/2012	-	1	-	-	**1**	WP 3-779	WP 3-1318
11	41483065	24207	L-021E TEST 0.31MI MP 116.16-116.46 PH1	KE1	7/1/2012	-	657,000	-	-	**657,000**	WP 3-782	WP 3-1319
12	41474092	23535	L-021F TEST 5.18MI MP 2.70-19.93 PH1	KE1	12/1/2012	-	2,373,000	-	-	**2,373,000**	WP 3-785	WP 3-1320
13	41474094	23538	L-021G TEST 2.54MI MP 0.00-2.54 PH1	KE1	12/1/2012	-	1,460,000	-	-	**1,460,000**	WP 3-788	WP 3-1321
14	41474099	23540	L-050A TEST 6.38MI MP 2.55-38.63 PH1	KE1	12/1/2014	-	-	-	2,486,000	**2,486,000**	WP 3-791	WP 3-1322
15	41482923	24212	L-050A-1 TEST 0.64MI MP 1.56-2.25 PH1	KE1	7/1/2013	-	-	908,000	-	**908,000**	WP 3-794	WP 3-1323
16	41483068	24168	L-057A-MC TEST 0.45MI MP 0.00-0.42 PH1	KE1	7/1/2014	-	-	-	922,000	**922,000**	WP 3-797	WP 3-1324
17	41482931	24183	L-057A-MD1 TEST 1.13MI MP 0.00-1.13 PH1	KE1	12/1/2012	-	968,000	-	-	**968,000**	WP 3-800	WP 3-1325
18	41482930	24178	L-057A-MD2 TEST 0.32MI MP 0.00-0.32 PH1	KE1	7/1/2014	-	-	-	877,000	**877,000**	WP 3-803	WP 3-1326
19	41474061	23496	L-100 TEST 10.36MI MP 138.43-150.13 PH1	KE1	12/1/2012	-	3,916,000	-	-	**3,916,000**	WP 3-806	WP 3-1327
20	P.03758	23500	L-101 TEST 0.66MI MP 2.45-10.52 PH1	KE1	12/1/2011	1,757,000	-	-	-	**1,757,000**	WP 3-809	WP 3-1328
21	41474063	23502	L-103 TEST 2.45MI MP 25.31-27.77PH1	KE1	12/1/2013	-	-	1,235,000	-	**1,235,000**	WP 3-812	WP 3-1329
22	P.03759	23542	L-105A TEST 4.76MI MP 38.00-46.91 PH1	KE1	12/1/2011	1,572,000	-	-	-	**1,572,000**	WP 3-815	WP 3-1330
23	P.03766	24204	L-105C TEST 1.74MI MP 0.00-1.76 PH1	KE1	12/1/2011	1,411,000	-	-	-	**1,411,000**	WP 3-818	WP 3-1331
24	P.03767	24560	L-105N_1 TEST 5.90MI MP 11.07-30.63 PH1	KE1	12/1/2011	3,931,000	-	-	-	**3,931,000**	WP 3-821	WP 3-1332
25	41473949	23491	L-105N_2 TEST 0.48MI MP 21.24-21.70 PH1	KE1	7/1/2012	-	1,007,000	-	-	**1,007,000**	WP 3-824	WP 3-1333
26	41474068	23505	L-109 TEST 3.40MI MP 7.57-48.84 PH1	KE1	12/1/2012	-	4,242,000	-	-	**4,242,000**	WP 3-827	WP 3-1334
27	41474070	23548	L-118A TEST 1.30MI MP 0.00-58.74 PH1	KE1	12/1/2012	1,067	2,167,933	-	-	**2,169,000**	WP 3-830	WP 3-1335
28	41474071	23550	L-118B TEST 16.44MI MP 1.04-20.07 PH1	KE1	12/1/2013	-	-	4,579,000	-	**4,579,000**	WP 3-833	WP 3-1336
29	41474072	23552	L-119A TEST 3.68MI MP 0.00-14.02 PH1	KE1	12/1/2012	-	1,643,000	-	-	**1,643,000**	WP 3-838	WP 3-1337
30	41482798	24262	L-119A-1 TEST 0.25MI MP 11.14.11.36 PH1	KE1	7/1/2013	-	-	801,000	-	**801,000**	WP 3-841	WP 3-1338
31	41474073	23554	L-119B TEST 6.91MI MP 0.00-10.02 PH1	KE1	12/1/2012	-	2,668,000	-	-	**2,668,000**	WP 3-844	WP 3-1339
32	41474075	23559	L-126A TEST 9.84MI MP 0.00-10.89 PH1	KE1	12/1/2014	71	-	-	3,116,929	**3,117,000**	WP 3-847	WP 3-1340
33	41474076	23561	L-126B TEST 10.14MI MP 0.00-10.57 PH1	KE1	12/1/2014	-	-	-	3,171,000	**3,171,000**	WP 3-850	WP 3-1341
34	P.03752	24699	L-131_1 TEST 5.59MI MP 49.36-54.91 PH1	KE1	12/1/2011	3,559,000	-	-	-	**3,559,000**	WP 3-853	WP 3-1342
35	41474018	23874	L-131_2 TEST 3.14MI MP 8.44-45.90 PH1	KE1	12/1/2012	-	2,680,000	-	-	**2,680,000**	WP 3-856	WP 3-1343
36	41474033	23471	L-131Z TEST 0.54MI MP 0.00-0.54 PH1	KE1	7/1/2013	-	-	890,000	-	**890,000**	WP 3-859	WP 3-1344
37	P.03760	24537	L-132_1 TEST 42.62MI MP 0.74-51.53 PH1	KE1	12/1/2011	21,498,000	-	-	-	**21,498,000**	WP 3-862	WP 3-1345
38	41474074	23557	L-132_2 TEST MP 1.91MI 40.05-49.71 PH1	KE1	12/1/2012	-	2,088,000	-	-	**2,088,000**	WP 3-870	WP 3-1347
39	P.03761	23480	L-132A TEST 1.45MI MP 0.01-1.46 PH1	KE1	12/1/2011	1,228,000	-	-	-	**1,228,000**	WP 3-873	WP 3-1348
40	41474035	23487	L-134A TEST 5.94MI MP 4.00-25.55 PH1	KE1	12/1/2014	-	-	-	2,156,000	**2,156,000**	WP 3-876	WP 3-1349

Table 3
Expenses by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
41	41474036	23489	L-137B TEST 5.29MI MP 0.00-7.37 PH1	KE1	12/1/2013	-	-	2,220,000	-	**2,220,000**	WP 3-879	WP 3-1350
42	41474080	23510	L-138 TEST 17.09MI MP 22.04-45.39 PH1	KE1	12/1/2012	-	5,841,000	-	-	**5,841,000**	WP 3-882	WP 3-1351
43	41474037	23493	L-142N TEST 11.67MI MP 0.00-14.05 PH1	KE1	12/1/2012	-	4,373,000	-	-	**4,373,000**	WP 3-886	WP 3-1352
44	41474038	23495	L-142S TEST 2.28MI MP 0.02-11.48 PH1	KE1	12/1/2012	-	1,637,000	-	-	**1,637,000**	WP 3-891	WP 3-1353
45	P.03762	24548	L-147 TEST 2.88MI MP 0.40-3.40 PH1	KE1	12/1/2011	2,491,000	-	-	-	**2,491,000**	WP 3-894	WP 3-1354
46	41474082	23513	L-148 TEST 17.62MI MP 0.00-17.63 PH1	KE1	12/1/2011	3,922,000	-	-	-	**3,922,000**	WP 3-897	WP 3-1355
47	41474083	23515	L-150 TEST 6.63MI MP 6.15-18.09 PH1	KE1	12/1/2013	-	-	2,699,000	-	**2,699,000**	WP 3-900	WP 3-1356
48	41474084	23517	L-151 TEST 0.42MI MP 10.81-11.23 PH1	KE1	7/1/2014	-	-	-	894,000	**894,000**	WP 3-903	WP 3-1357
49	P.03764	24554	L-153_1 TEST 17.35MI MP 0.00-22.87PH1	KE1	12/1/2011	9,189,000	-	-	-	**9,189,000**	WP 3-906	WP 3-1358
50	41473934	23582	L-153_2 TEST 10.86MI MP 3.58-27.88PH1	KE1	12/1/2012	-	4,607,000	-	-	**4,607,000**	WP 3-911	WP 3-1359
51	41474040	23498	L-158-1 TEST 2.58MI MP 11.07-13.65 PH1	KE1	12/1/2014	-	-	-	1,296,000	**1,296,000**	WP 3-914	WP 3-1360
52	41474041	23499	L-162A TEST 1.69MI MP 4.41-9.03 PH1	KE1	12/1/2013	-	-	1,338,000	-	**1,338,000**	WP 3-917	WP 3-1361
53	41474042	23501	L-172A TEST 2.11MI MP 35.51-67.50 PH1	KE1	12/1/2012	-	2,407,000	-	-	**2,407,000**	WP 3-920	WP 3-1362
54	41474043	23503	L-177A TEST 0.33MI MP 88.50-88.83 PH1	KE1	7/1/2012	-	828,000	-	-	**828,000**	WP 3-923	WP 3-1363
55	41474044	23506	L-177B TEST 6.65MI MP 0.86-7.51 PH1	KE1	12/1/2013	-	-	2,221,000	-	**2,221,000**	WP 3-926	WP 3-1364
56	41474046	23509	L-181B TEST 1.55MI MP 0.64-2.17 PH1	KE1	12/1/2013	-	-	1,076,000	-	**1,076,000**	WP 3-929	WP 3-1365
57	41482928	24217	L-183 TEST 0.32MI MP 5.96-6.29 PH1	KE1	7/1/2014	-	-	-	876,000	**876,000**	WP 3-932	WP 3-1366
58	41474086	23521	L-186 TEST 2.08MI MP 9.20-26.13 PH1	KE1	12/1/2014	-	-	-	1,681,000	**1,681,000**	WP 3-935	WP 3-1367
59	41474087	23524	L-187 TEST 39.21MI MP 22.58-65.70 PH1	KE1	12/1/2013	-	-	9,681,000	-	**9,681,000**	WP 3-938	WP 3-1368
60	P.03765	24555	L-191 TEST 3.98MI MP 2.74-10.57 PH1	KE1	12/1/2011	2,415,000	-	-	-	**2,415,000**	WP 3-942	WP 3-1369
61	41474047	23511	L-191-1 TEST 10.07MI MP 9.59-35.83 PH1	KE1	12/1/2012	-	3,494,000	-	-	**3,494,000**	WP 3-945	WP 3-1370
62	41474048	23514	L-191A TEST 4.89MI MP 0.00-4.84 PH1	KE1	12/1/2014	-	-	-	1,714,000	**1,714,000**	WP 3-948	WP 3-1371
63	41474089	23494	L-195A3-1 TEST 0.48MI MP 0.00-0.48 PH1	KE1	7/1/2013	-	-	878,000	-	**878,000**	WP 3-951	WP 3-1372
64	41474060	23527	L-196A TEST 0.46MI MP 11.49-11.93 PH1	KE1	7/1/2014	-	-	-	902,000	**902,000**	WP 3-954	WP 3-1373
65	41474051	23520	L-197B TEST 5.18MI MP 0.00-5.49 PH1	KE1	12/1/2014	-	-	-	1,762,000	**1,762,000**	WP 3-957	WP 3-1374
66	41474052	23522	L-197C-1 TEST 2.34MI MP 14.73-17.05 PH1	KE1	12/1/2014	-	-	-	1,251,000	**1,251,000**	WP 3-960	WP 3-1375
67	41482859	24205	L-197C-2 TEST 2.88MI MP 0.55-3.43 PH1	KE1	12/1/2014	-	-	-	1,350,000	**1,350,000**	WP 3-963	WP 3-1376
68	41482793	24264	L-200A-1 TEST 0.34MI MP 1.08-1.42 PH1	KE1	7/1/2012	-	829,000	-	-	**829,000**	WP 3-966	WP 3-1377
69	41474101	23525	L-210B TEST 13.54MI MP 7.57-25.98 PH1	KE1	12/1/2012	-	4,965,000	-	-	**4,965,000**	WP 3-969	WP 3-1378
70	41482927	24216	L-210C TEST 0.10MI MP 31.64-31.74 PH1	KE1	7/1/2012	-	1	-	-	**1**	WP 3-972	WP 3-1379
71	41474095	23528	L-220 TEST 4.58MI MP 23.14-27.68 PH1	KE1	12/1/2014	-	-	-	1,661,000	**1,661,000**	WP 3-975	WP 3-1380
72	P.03754	24495	L-300A_1 TEST 80.13MI MP 0.29-502.24 PH1	KE1	12/1/2011	32,911,000	-	-	-	**32,911,000**	WP 3-978	WP 3-1381
73	41474039	23497	L-300A_2 TEST 17.20MI MP 230.32-490.59 PH1	KE1	12/1/2012	-	11,359,000	-	-	**11,359,000**	WP 3-985	WP 3-1384
74	P.03754	24492	L-300A-1 TEST 0.61MI MP 156.40-157.01 PH1	KE1	12/1/2011	1,128,000	-	-	-	**1,128,000**	WP 3-989	WP 3-1385
75	P.03756	24521	L-300B_1 TEST 71.84MI MP 0.00-218.67 PH1	KE1	12/1/2011	24,871,000	-	-	-	**24,871,000**	WP 3-992	WP 3-1386
76	41483066	24219	L-300B_2 TEST 12.35MI MP 148.90-283.14 PH1	KE1	12/1/2014	-	-	-	6,348,000	**6,348,000**	WP 3-998	WP 3-1388
77	41474056	23536	L-303 TEST 1.16MI MP 19.21-20.43 PH1	KE1	2/1/2012	-	1,524,000	-	-	**1,524,000**	WP 3-1001	WP 3-1389
78	41474096	23529	L-306 TEST 7.24MI MP 0.00-70.02 PH1	KE1	12/1/2012	-	3,555,000	-	-	**3,555,000**	WP 3-1004	WP 3-1390
79	41474097	23530	L-314 TEST 4.34MI MP 20.91-24.92 PH1	KE1	12/1/2014	-	-	-	1,617,000	**1,617,000**	WP 3-1007	WP 3-1391
80	41474098	23492	L-318-12 TEST 2.02MI MP 0.00-0.00 PH1	KE1	12/1/2014	-	-	-	1,193,000	**1,193,000**	WP 3-1010	WP 3-1392

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 3
Expenses by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
81	41483067	24220	L-331A TEST 0.34MI MP 8.06-8.40 PH1	KE1	7/1/2013	-	-	1	-	**1**	WP 3-1013	WP 3-1393
82	41474057	23539	L-400_1 TEST 17MI MP 80.04-298.84 PH1	KE1	12/1/2013	-	-	10,051,000	-	**10,051,000**	WP 3-1016	WP 3-1394
83	41483064	24201	L-400_2 TEST 17.5MI MP 122.22-139.73 PH1	KE1	12/1/2014	-	-	-	13,089,000	**13,089,000**	WP 3-1019	WP 3-1395
84	P.03757	23551	L-400-3 TEST 4.00MI MP 295.91-299.91 PH1	KE1	12/1/2011	2,424,000	-	-	-	**2,424,000**	WP 3-1022	WP 3-1396
85	41474031	23531	L-401 TEST 0.80MI MP 323.44-326.76 PH1	KE1	12/1/2012	-	1,973,000	-	-	**1,973,000**	WP 3-1025	WP 3-1397
86	41473886	23556	DFM-0115-01 TEST 0.40MI MP 0.00-0.41 PH1	KE1	12/1/2014	-	-	-	897,000	**897,000**	WP 3-1028	WP 3-1398
87	41473887	23558	DFM-0126-01 TEST 0.07MI MP 1.76-1.84 PH1	KE1	7/1/2012	-	1	-	-	**1**	WP 3-1031	WP 3-1399
88	41473888	23560	DFM-0141-01 TEST 0.43MI MP 0.00-0.42 PH1	KE1	7/1/2014	-	-	-	896,000	**896,000**	WP 3-1034	WP 3-1400
89	41482926	24215	DFM-0210-01 TEST 6.27MI MP 0.00-6.62 PH1	KE1	12/1/2013	-	-	2,154,000	-	**2,154,000**	WP 3-1037	WP 3-1401
90	41473891	23566	DFM-0211-01 TEST 0.68MI MP 0.00-0.68 PH1	KE1	7/1/2014	-	-	-	680,000	**680,000**	WP 3-1040	WP 3-1402
91	41473985	23927	DFM-0213-02 TEST 0.87MI MP 0.00-0.91 PH1	KE1	7/1/2014	-	-	-	981,000	**981,000**	WP 3-1043	WP 3-1403
92	41473893	23570	DFM-0215-01 TEST 0.95MI MP 0.00-0.98 PH1	KE1	7/1/2013	-	-	962,000	-	**962,000**	WP 3-1046	WP 3-1404
93	41473895	23574	DFM-0401-01 TEST 5.44MI MP 0.03-5.48 PH1	KE1	12/1/2012	-	1,733,000	-	-	**1,733,000**	WP 3-1049	WP 3-1405
94	41473897	23578	DFM-0402-01 TEST 0.69MI MP 0.27-2.36 PH1	KE1	7/1/2012	-	1,370,000	-	-	**1,370,000**	WP 3-1052	WP 3-1406
95	41473920	23584	DFM-0405-01 TEST 3.25MI MP 1.09-16.54 PH1	KE1	12/1/2013	-	-	1,255,000	-	**1,255,000**	WP 3-1055	WP 3-1407
96	41473922	23588	DFM-0406-03 TEST 0.76MI MP 0.08-0.81 PH1	KE1	7/1/2014	-	-	-	955,000	**955,000**	WP 3-1059	WP 3-1408
97	41473923	23590	DFM-0407-01 TEST 4.36MI MP 0.00-4.34 PH1	KE1	12/1/2012	-	1,079,000	-	-	**1,079,000**	WP 3-1062	WP 3-1409
98	41473924	23563	DFM-0601-01 TEST 0.36MI MP 0.09-0.46 PH1	KE1	7/1/2014	-	-	-	556,000	**556,000**	WP 3-1065	WP 3-1410
99	41473925	23565	DFM-0604-01 TEST 1.08MI MP 0.00-4.71 PH1	KE1	12/1/2013	-	-	1,234,000	-	**1,234,000**	WP 3-1068	WP 3-1411
100	41473926	23567	DFM-0604-06 TEST 2.29MI MP 0.00-2.28 PH1	KE1	12/1/2014	-	-	-	1,240,000	**1,240,000**	WP 3-1071	WP 3-1412
101	41473927	23569	DFM-0604-07 TEST 6.25MI MP 0.01-6.41 PH1	KE1	12/1/2013	-	-	2,096,000	-	**2,096,000**	WP 3-1074	WP 3-1413
102	41473930	23575	DFM-0611-01 TEST 1.07MI MP 0.00-1.07 PH1	KE1	12/1/2012	-	978,000	-	-	**978,000**	WP 3-1077	WP 3-1414
103	41473931	23577	DFM-0611-02 TEST 1.50MI MP 0.00-1.91 PH1	KE1	12/1/2012	-	1,023,000	-	-	**1,023,000**	WP 3-1080	WP 3-1415
104	41482853	24196	DFM-0611-05 TEST 0.12MI MP 0.00-0.06 PH1	KE1	7/1/2012	-	909,000	-	-	**909,000**	WP 3-1084	WP 3-1416
105	41473962	23884	DFM-0621-01 TEST 0.68MI MP 0.02-0.70 PH1	KE1	7/1/2014	-	-	-	909,000	**909,000**	WP 3-1087	WP 3-1417
106	41473936	23587	DFM-0630-01 TEST 0.07MI MP 1.33-1.40 PH1	KE1	7/1/2014	-	-	-	831,000	**831,000**	WP 3-1090	WP 3-1418
107	41473965	23835	DFM-0638-02 TEST 1.24MI MP 1.69-2.93 PH1	KE1	12/1/2014	-	-	-	1	**1**	WP 3-1093	WP 3-1419
108	41473966	23843	DFM-0651-01 TEST 0.86MI MP 1.01-1.87 PH1	KE1	7/1/2012	-	1	-	-	**1**	WP 3-1096	WP 3-1420
109	41473969	23861	DFM-0813-01 TEST 1.30MI MP 0.00-1.29 PH1	KE1	12/1/2012	-	1,002,000	-	-	**1,002,000**	WP 3-1099	WP 3-1421
110	41473970	23866	DFM-0813-02 TEST 0.50MI MP 0.00-0.50 PH1	KE1	7/1/2014	-	-	-	910,000	**910,000**	WP 3-1102	WP 3-1422
111	41473971	23871	DFM-0814-05 TEST 0.31MI MP 0.00-0.31 PH1	KE1	7/1/2013	-	-	849,000	-	**849,000**	WP 3-1105	WP 3-1423
112	41473972	23876	DFM-0817-01 TEST 1.31MI MP 0.00-1.30 PH1	KE1	12/1/2013	-	-	1,034,000	-	**1,034,000**	WP 3-1108	WP 3-1424
113	41473974	23885	DFM-1004-01 TEST 0.35MI MP 4.40-4.75 PH1	KE1	7/1/2014	-	-	-	882,000	**882,000**	WP 3-1111	WP 3-1425
114	41473975	23892	DFM-1023-01 TEST 2.83MI MP 0.00-2.83 PH1	KE1	12/1/2013	-	-	1,249,000	-	**1,249,000**	WP 3-1114	WP 3-1426
115	41473976	23894	DFM-1027-01 TEST 1.21MI MP 3.46-6.58 PH1	KE1	12/1/2014	-	-	-	1,293,000	**1,293,000**	WP 3-1117	WP 3-1427
116	41483062	24193	DFM-1027-04 TEST 0.92MI MP 0.70-1.62 PH1	KE1	12/1/2014	-	-	-	992,000	**992,000**	WP 3-1120	WP 3-1428
117	41482847	24187	DFM-1202-01 TEST 2.13MI MP 0.00-2.13 PH1	KE1	12/1/2012	-	1,367,000	-	-	**1,367,000**	WP 3-1123	WP 3-1429
118	41482846	24186	DFM-1202-02 TEST 0.39MI MP 2.00-2.39 PH1	KE1	7/1/2013	-	-	1,000,000	-	**1,000,000**	WP 3-1126	WP 3-1430
119	41482845	24185	DFM-1202-03 TEST 0.39MI MP 0.00-0.39 PH1	KE1	7/1/2014	-	-	-	889,000	**889,000**	WP 3-1129	WP 3-1431
120	41473979	23901	DFM-1202-16 TEST 2.50MI MP 0.08-2.58 PH1	KE1	12/1/2013	-	-	1,245,000	-	**1,245,000**	WP 3-1132	WP 3-1432

Table 3
Expenses by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
121	41473980	23903	DFM-1209-02 TEST 1.48MI MP 0.00-1.47 PH1	KE1	12/1/2013	3,023	-	1,059,977	-	**1,063,000**	WP 3-1135	WP 3-1433
122	41473982	23918	DFM-1301-01 TEST 4.40MI MP 0.00-4.63 PH1	KE1	12/1/2014	-	-	-	1,874,000	**1,874,000**	WP 3-1138	WP 3-1434
123	41473961	23878	DFM-1306-01 TEST 0.72MI MP 0.01-0.72 PH1	KE1	7/1/2014	-	-	-	949,000	**949,000**	WP 3-1141	WP 3-1435
124	41473987	23931	DFM-1310-01 TEST 1.28MI MP 0.00-1.29 PH1	KE1	12/1/2014	-	-	-	1,058,000	**1,058,000**	WP 3-1144	WP 3-1436
125	41473988	23934	DFM-1401-01 TEST 0.80MI MP 0.00-0.79 PH1	KE1	7/1/2012	-	1,061,000	-	-	**1,061,000**	WP 3-1147	WP 3-1437
126	41473990	23911	DFM-1501-01 TEST 5.55MI MP 0.00-6.88 PH1	KE1	12/1/2014	-	-	-	2,086,000	**2,086,000**	WP 3-1150	WP 3-1438
127	41473991	23912	DFM-1501-02 TEST 0.80MI MP 0.62-2.44 PH1	KE1	12/1/2014	-	-	-	1,218,000	**1,218,000**	WP 3-1153	WP 3-1439
128	41473992	23913	DFM-1502-02 TEST 1.60MI MP 0.00-1.60 PH1	KE1	12/1/2014	-	-	-	1,115,000	**1,115,000**	WP 3-1156	WP 3-1440
129	41473933	23581	DFM-1502-06 TEST 0.32MI MP 0.00-0.32 PH1	KE1	7/1/2014	-	-	-	876,000	**876,000**	WP 3-1159	WP 3-1441
130	41473932	23579	DFM-1502-11 TEST 1.98MI MP 0.00-2.96 PH1	KE1	12/1/2014	-	-	-	1,434,000	**1,434,000**	WP 3-1162	WP 3-1442
131	41474066	23545	DFM-1519-01 TEST 0.55MI MP 1.48-2.03 PH1	KE1	7/1/2013	-	-	891,000	-	**891,000**	WP 3-1165	WP 3-1443
132	41473999	23841	DFM-1601-09 TEST 0.86MI MP 0.00-0.86 PH1	KE1	7/1/2014	-	-	-	975,000	**975,000**	WP 3-1168	WP 3-1444
133	41482842	24272	DFM-1603-01 TEST 1.23MI MP 0.07-1.30 PH1	KE1	12/1/2013	-	-	1,020,000	-	**1,020,000**	WP 3-1171	WP 3-1445
134	41474000	23842	DFM-1603-03 TEST 0.48MI MP 0.00-0.48 PH1	KE1	7/1/2014	-	-	-	863,000	**863,000**	WP 3-1174	WP 3-1446
135	41474002	23847	DFM-1614-01 TEST 3.97MI MP 0.00-3.97 PH1	KE1	12/1/2014	-	-	-	1,549,000	**1,549,000**	WP 3-1177	WP 3-1447
136	41474005	23856	DFM-1615-01 TEST 8.03MI MP 6.72-14.74 PH	KE1	12/1/2012	-	2,393,000	-	-	**2,393,000**	WP 3-1180	WP 3-1448
137	41474007	23857	DFM-1615-07 TEST 0.25MI MP 0.01-0.25 PH1	KE1	7/1/2014	-	-	-	1	**1**	WP 3-1183	WP 3-1449
138	41483061	24274	DFM-1617-01 TEST 0.82MI MP 0.00-0.82 PH1	KE1	7/1/2013	-	-	939,000	-	**939,000**	WP 3-1187	WP 3-1450
139	41474008	23860	DFM-1622-01 TEST 1.00MI MP 0.00-1.00 PH1	KE1	7/1/2014	-	-	-	998,000	**998,000**	WP 3-1190	WP 3-1451
140	41474001	23846	DFM-1640-01 TEST 0.70MI MP 0.00-0.70 PH1	KE1	7/1/2014	-	-	-	945,000	**945,000**	WP 3-1193	WP 3-1452
141	41474011	23872	DFM-1813-02 TEST 5.17MI MP 8.93-16.39 PH1	KE1	12/1/2013	-	-	1,957,000	-	**1,957,000**	WP 3-1196	WP 3-1453
142	41474012	23877	DFM-1815-02 TEST 9.80MI MP 6.50-16.85 PH1	KE1	12/1/2013	-	-	3,020,000	-	**3,020,000**	WP 3-1199	WP 3-1454
143	41474013	23880	DFM-1815-15 TEST 1.98MI MP 0.18-2.13 PH1	KE1	12/1/2013	-	-	1,357,000	-	**1,357,000**	WP 3-1202	WP 3-1455
144	P.03751	24484	DFM-1816-01_1 TEST 18.55MI MP 0.00-18.25 PH1	KE1	12/31/2011	2,631,000	-	-	-	**2,631,000**	WP 3-1205	WP 3-1456
145	41473986	23929	DFM-1816-01_2 TEST 9.17MI MP 8.44-18.25 PH1	KE1	12/1/2013	-	-	2,668,000	-	**2,668,000**	WP 3-1209	WP 3-1457
146	41474015	23858	DFM-1816-02 TEST 0.12MI MP 0.00-0.12 PH1	KE1	7/1/2013	-	-	816,000	-	**816,000**	WP 3-1212	WP 3-1458
147	41474016	23864	DFM-1816-05 TEST 0.80MI MP 0.00-0.80 PH1	KE1	7/1/2014	-	-	-	963,000	**963,000**	WP 3-1215	WP 3-1459
148	41474017	23870	DFM-1816-15 TEST 6.04MI MP 0.00-6.01 PH1	KE1	12/1/2013	-	-	2,112,000	-	**2,112,000**	WP 3-1218	WP 3-1460
149	41474019	23879	DFM-1819-01 TEST 0.64MI MP 0.42-1.07 PH1	KE1	7/1/2014	-	-	-	757,000	**757,000**	WP 3-1221	WP 3-1461
150	41474020	23883	DFM-1869-01 TEST 0.16MI MP 0.00-0.16 PH1	KE1	7/1/2014	-	-	-	847,000	**847,000**	WP 3-1224	WP 3-1462
151	41474021	23886	DFM-1870-01 TEST 3.33MI MP 0.00-3.33 PH1	KE1	12/1/2014	-	-	-	1,432,000	**1,432,000**	WP 3-1227	WP 3-1463
152	41482848	24188	DFM-2403-12 TEST 2.88MI MP 0.00-2.88 PH1	KE1	12/1/2012	-	1,250,000	-	-	**1,250,000**	WP 3-1230	WP 3-1464
153	41474024	23895	DFM-2408-01 TEST 0.99MI MP 2.32-2.72 PH1	KE1	7/1/2014	-	-	-	998,000	**998,000**	WP 3-1233	WP 3-1465
154	41474028	23905	DFM-3010-01 TEST 1.27MI MP 0.00-1.27 PH1	KE1	12/1/2012	995	995,005	-	-	**996,000**	WP 3-1236	WP 3-1466
155	41474029	23906	DFM-3017-01 TEST 6.68MI MP 0.02-6.95 PH1	KE1	12/1/2013	-	-	2,226,000	-	**2,226,000**	WP 3-1239	WP 3-1467
156	41474030	23907	DFM-6603-01 TEST 2.18MI MP 3.96-6.14 PH1	KE1	12/1/2014	-	-	-	1,223,000	**1,223,000**	WP 3-1242	WP 3-1468
157	41482924	24213	DFM-7204-01 TEST 0.06MI MP 1.90-1.96 PH1	KE1	7/1/2014	-	-	-	829,000	**829,000**	WP 3-1245	WP 3-1469
158	41482854	24197	DFM-7218-01 TEST 1.32MI MP 0.00-1.32 PH1	KE1	12/1/2013	-	-	1,034,000	-	**1,034,000**	WP 3-1248	WP 3-1470
159	41473939	23467	DFM-7221-10 TEST 6.10MI MP 7.45-15.99 PH1	KE1	12/1/2012	-	2,050,000	-	-	**2,050,000**	WP 3-1251	WP 3-1471
160	41473941	23470	DFM-7222-01 TEST 13.55MI MP 0.09-13.99 PH1	KE1	12/1/2014	-	-	-	3,991,000	**3,991,000**	WP 3-1255	WP 3-1472

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 3, Pipeline Modernization

Table 3
Expenses by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
161	41473942	23472	DFM-7223-01 TEST 9.90MI MP 0.15-10.05 PH1	KE1	12/1/2013	-	-	2,798,000	-	**2,798,000**	WP 3-1259	WP 3-1473
162	41473943	23474	DFM-7224-09 TEST 1.35MI MP 0.00-1.35 PH1	KE1	12/1/2014	-	-	-	1,070,000	**1,070,000**	WP 3-1262	WP 3-1474
163	41473944	23477	DFM-7224-12 TEST 0.48MI MP 0.25-0.73 PH1	KE1	7/1/2013	-	-	880,000	-	**880,000**	WP 3-1265	WP 3-1475
164	41473945	23478	DFM-7226-01 TEST 5.59MI MP 0.00-5.59 PH1	KE1	12/1/2013	-	-	2,034,000	-	**2,034,000**	WP 3-1268	WP 3-1476
165	41473946	23481	DFM-7226-02 TEST 0.39MI MP 3.47-3.86 PH1	KE1	7/1/2013	-	-	869,000	-	**869,000**	WP 3-1271	WP 3-1477
166	41473947	23483	DFM-7226-13 TEST 0.25MI MP 0.00-0.25 PH1	KE1	7/1/2014	-	-	-	864,000	**864,000**	WP 3-1274	WP 3-1478
167	41482925	24214	DFM-7227-05 TEST 0.19MI MP 0.00-0.19 PH1	KE1	7/1/2013	-	-	829,000	-	**829,000**	WP 3-1277	WP 3-1479
168			**Total MAT KE1 - Imp Plan Pressure Test**			**116,943,156**	**93,728,943**	**84,512,978**	**93,860,931**	**389,046,008**		
169												
170	41476259	24027	L-101 MP 0.00-11.62 ILI & ANALYSIS PH1	KE3	11/1/2014	-	-	-	1,087,000	**1,087,000**	WP 3-1280	WP 3-1480
171	41476300	24028	L-101 MP 11.62-33.68 ILI & ANALYSIS PH1	KE3	11/1/2014	-	-	-	1,655,000	**1,655,000**	WP 3-1284	WP 3-1481
172	41482821	24010	L-131 MP 50.5-57.4 ILI & ANALYSIS PH-1	KE3	11/1/2013	-	-	300,000	497,000	**797,000**	WP 3-1289	WP 3-1482
173	41482737	24026	L-132 MP 31.9-38.4 ILI & ANALYSIS PH-1	KE3	11/1/2013	-	-	325,000	499,000	**824,000**	WP 3-1292	WP 3-1483
174	41483499	24024	L-300A MP 299-352 ILI & ANALYSIS PH-1	KE3	11/1/2014	-	-	-	1,326,000	**1,326,000**	WP 3-1295	WP 3-1484
175	41482736	24022	L-300A MP 353-391 ILI & ANALYSIS PH-1	KE3	11/1/2013	-	-	500,000	788,000	**1,288,000**	WP 3-1299	WP 3-1485
176	41482735	24018	L-300B MP 299-353 ILI & ANALYSIS PH-1	KE3	11/1/2014	-	-	-	1,326,000	**1,326,000**	WP 3-1302	WP 3-1486
177	41482734	24015	L-300B MP 353-390 ILI & ANALYSIS PH-1	KE3	11/1/2013	-	-	600,000	688,000	**1,288,000**	WP 3-1305	WP 3-1487
178			**Total MAT KE3 - Imp Plan Pipeline ILI**			**-**	**-**	**1,725,000**	**7,866,000**	**9,591,000**		
179												
180	41521348	24913	Engineering Condition Assessment	KEX	12/31/2014	-	1,000,000	1,030,000	1,060,000	**3,090,000**	WP 3-1308	n/a
181	41521349	24914	Remaining Life Fatigue Analysis	KEX	12/31/2014	100,000	150,000	25,000	25,000	**300,000**	WP 3-1309	n/a
182	41457916	23163	Imp Plan - Pipeline Planning Exp	KEX	12/31/2011	1,500,000	-	-	-	**1,500,000**	WP 3-1310	n/a
183			**Total MAT KEX - Imp Plan Pipeline Other**			**1,600,000**	**1,150,000**	**1,055,000**	**1,085,000**	**4,890,000**		
184												
185			**Total Pipeline Modernization Expense Projects**			**122,658,156**	**94,878,943**	**87,292,978**	**102,811,931**	**407,642,008**		

Exhibit B

Valve Automation Program Project Summary

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 4, Valve Automation

Table 1
Capital Expenditures and Expenses by Maintenance Activity Type (MAT)

MAT	MAT Description	2011	2012	2013	2014	Total	Tables 2 and 3 Reference
44A	StanPac Capital	-	1,948,663	4,610,471	-	**6,559,134**	WP 4-2, Table 2, Line 10
2H3	Imp Plan Valve Automation	13,686,700	37,599,704	48,714,483	25,968,238	**125,969,125**	WP 4-4, Table 2, Line 92
	Total Capital Expenditures	**13,686,700**	**39,548,367**	**53,324,954**	**25,968,238**	**132,528,258**	WP 4-4, Table 2, Line 94
KE4	Imp Plan Station Other	803,206	2,581,376	3,108,541	3,813,648	**10,306,771**	WP 4-278, Table 3, Line 3
KEX	Imp Plan Pipeline Other	800,000	-	-	-	**800,000**	WP 4-278, Table 3, Line 6
	Total Expenses	**1,603,206**	**2,581,376**	**3,108,541**	**3,813,648**	**11,106,771**	WP 4-278, Table 3, Line 8
	Total Valve Automation Costs	**15,289,906**	**42,129,743**	**56,433,495**	**29,781,886**	**143,635,029**	

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 4, Valve Automation

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
1	97000502	23619	VALVE AUTO - ANTIOCH TERMINAL, PH. 1	44A	3/31/2013	-	108,147	153,864	-	**262,011**	WP 4-5	WP 4-198
2	97000503	23620	VALVE AUTO - ANTIOCH TOWN METER STA, PH. 1	44A	3/31/2013	-	695,382	989,344	-	**1,684,726**	WP 4-7	WP 4-199
3	97000501	23621	VALVE AUTO - SP3-LINE 191 MTR STA, PH. 1	44A	3/31/2013	-	546,380	777,354	-	**1,323,734**	WP 4-9	WP 4-200
4	97000521	23622	VALVE AUTO - LOS MEDANOS, PH. 1	44A	3/31/2013	-	299,031	425,442	-	**724,473**	WP 4-11	WP 4-201
5	97000504	23623	VALVE AUTO - CONCORD METER STA, PH. 1	44A	6/30/2013	-	128,029	967,286	-	**1,095,315**	WP 4-13	WP 4-202
6	97000505	23624	VALVE AUTO - VINE HILL, PH. 1	44A	6/30/2013	-	93,189	704,062	-	**797,251**	WP 4-15	WP 4-203
7	97000506	23626	VALVE AUTO - "C" STREET STA, PH. 1	44A	6/30/2013	-	44,189	333,859	-	**378,048**	WP 4-17	WP 4-204
8	97000507	23627	VALVE AUTO - FRANKLIN CANYON, PH. 1	44A	6/30/2013	-	12,252	92,564	-	**104,816**	WP 4-19	WP 4-205
9	97000508	23629	VALVE AUTO - SAN PABLO, PH. 1	44A	6/30/2013	-	22,064	166,696	-	**188,760**	WP 4-21	WP 4-206
10			**Total MAT 44A - StanPac Capital**			**-**	**1,948,663**	**4,610,471**	**-**	**6,559,134**		
11												
12	30842306	23442	VALVE AUTO - MILPITAS TERMINAL, PH. 1	2H3	12/31/2011	2,740,284	87,395	-	-	**2,827,679**	WP 4-23	WP 4-207
13	30842318	23440	VALVE AUTO - SIERRA VISTA STN, PH. 1	2H3	12/31/2011	907,628	28,947	-	-	**936,575**	WP 4-26	WP 4-208
14	30842310	23441	VALVE AUTO - RENGSTORFF STN, PH. 1	2H3	12/31/2011	2,174,999	69,367	-	-	**2,244,366**	WP 4-28	WP 4-209
15	30842297	23439	VALVE AUTO - LARKSPUR DR, PH. 1	2H3	12/31/2011	2,758,056	87,962	-	-	**2,846,018**	WP 4-30	WP 4-210
16	30842314	23438	VALVE AUTO - SAN ANDREAS, PH. 1	2H3	12/31/2011	945,614	30,158	-	-	**975,772**	WP 4-33	WP 4-211
17	30842291	23380	VALVE AUTO - HEALY STATION, PH. 1	2H3	12/31/2011	460,725	14,694	-	-	**475,419**	WP 4-35	WP 4-212
18	30840648	23379	VALVE AUTO - SF GAS LOAD CENTER, PH. 1	2H3	12/31/2011	1,157,871	36,928	-	-	**1,194,799**	WP 4-37	WP 4-213
19	30842276	23462	VALVE AUTO - CROSSMAN AVE, PH. 1	2H3	3/31/2012	2,164,894	69,044	-	-	**2,233,938**	WP 4-39	WP 4-214
20	30842323	23594	VALVE AUTO - VAN BUREN & RINGWOOD, PH. 1	2H3	9/30/2012	44,130	2,229,826	-	-	**2,273,956**	WP 4-41	WP 4-215
21	30842274	23597	VALVE AUTO - COMMERCIAL WAY, PH. 1	2H3	9/30/2012	46,932	2,371,409	-	-	**2,418,341**	WP 4-43	WP 4-216
22	30842271	23598	VALVE AUTO - BIRCH & S. DELAWARE, PH. 1	2H3	9/30/2012	47,291	2,389,581	-	-	**2,436,872**	WP 4-45	WP 4-217
23	30842302	23599	VALVE AUTO - LOMITA PARK, PH. 1	2H3	9/30/2012	7,757	391,932	-	-	**399,689**	WP 4-47	WP 4-218
24	30842290	23600	VALVE AUTO - HAMLIN COURT, PH. 1	2H3	9/30/2012	31,327	1,582,896	-	-	**1,614,223**	WP 4-49	WP 4-219
25	30842316	23601	VALVE AUTO - SAND HILL, PH. 1	2H3	9/30/2012	55,416	2,800,107	-	-	**2,855,523**	WP 4-52	WP 4-220
26	30842283	23602	VALVE AUTO - EDGEWOOD, PH. 1	2H3	9/30/2012	72,427	3,659,656	-	-	**3,732,083**	WP 4-55	WP 4-221
27	30843884	23603	VALVE AUTO - CRYSTAL SPRINGS, PH. 1	2H3	12/31/2012	-	2,447,714	219,285	-	**2,666,999**	WP 4-58	WP 4-222
28	30842289	23970	VALVE AUTO - HALF MOON BAY TAP, PH. 1	2H3	12/31/2012	-	653,658	58,560	-	**712,218**	WP 4-61	WP 4-223
29	30842319	23604	VALVE AUTO - SULLIVAN AVE, PH. 1	2H3	12/31/2012	-	367,937	32,963	-	**400,900**	WP 4-63	WP 4-224
30	30842299	23605	VALVE AUTO - LAWRENCE & LAKEHAVEN, PH. 1	2H3	12/31/2012	-	3,003,316	269,060	-	**3,272,376**	WP 4-65	WP 4-225
31	30842303	23606	VALVE AUTO - MARTIN STATION, PH. 1	2H3	12/31/2012	-	333,672	29,893	-	**363,565**	WP 4-68	WP 4-226
32	30842270	23607	VALVE AUTO - BAYSHORE & GENEVA, PH. 1	2H3	12/31/2012	-	849,104	76,069	-	**925,173**	WP 4-70	WP 4-227
33	30842312	23608	VALVE AUTO - ROUSSEAU STREET, PH. 1	2H3	12/31/2012	-	2,530,287	226,682	-	**2,756,969**	WP 4-72	WP 4-228
34	30842280	23609	VALVE AUTO - DIANA, PH. 1	2H3	12/31/2012	-	1,421,651	127,362	-	**1,549,013**	WP 4-75	WP 4-229
35	30842293	23611	VALVE AUTO - HWY 101 & SCHELLER, PH. 1	2H3	12/31/2012	-	614,352	55,038	-	**669,390**	WP 4-77	WP 4-230
36	30842287	23613	VALVE AUTO - FONTANOSO, PH. 1	2H3	3/31/2013	-	375,786	534,643	-	**910,429**	WP 4-79	WP 4-231
37	30842269	23971	VALVE AUTO - ANZAR TAP STATION, PH. 1	2H3	3/31/2013	-	692,378	985,070	-	**1,677,448**	WP 4-81	WP 4-232
38	30842266	23614	VALVE AUTO - ALUM ROCK, PH. 1	2H3	3/31/2013	-	430,359	612,287	-	**1,042,646**	WP 4-83	WP 4-233
39	30842261	23615	VALVE AUTO - 7A & 7B PLS, PH. 1	2H3	3/31/2013	-	416,267	592,237	-	**1,008,504**	WP 4-85	WP 4-234
40	30842305	23618	VALVE AUTO - MAYBURY, PH. 1	2H3	3/31/2013	-	281,692	400,773	-	**682,465**	WP 4-88	WP 4-235

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 4, Valve Automation

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
41	30847360	24281	VALVE AUTO - ANTIOCH TERMINAL, PH. 1	2H3	3/31/2013	-	1,206,191	1,716,090	-	**2,922,281**	WP 4-90	WP 4-198
42	30847361	24283	VALVE AUTO - ANTIOCH TOWN MTR STA, PH. 1	2H3	3/31/2013	-	811,279	1,154,234	-	**1,965,513**	WP 4-92	WP 4-199
43	30847366	24284	VALVE AUTO - SP3-LINE 191 MTR STA, PH. 1	2H3	3/31/2013	-	257,251	366,000	-	**623,251**	WP 4-94	WP 4-200
44	30847362	24285	VALVE AUTO - CONCORD METER STA, PH. 1	2H3	6/30/2013	-	67,011	506,285	-	**573,296**	WP 4-96	WP 4-202
45	30847363	24286	VALVE AUTO - "C" STREET STA, PH. 1	2H3	6/30/2013	-	40,919	309,153	-	**350,072**	WP 4-98	WP 4-204
46	30847364	24287	VALVE AUTO - FRANKLIN CANYON, PH. 1	2H3	6/30/2013	-	104,227	787,455	-	**891,682**	WP 4-100	WP 4-205
47	30847365	24288	VALVE AUTO - SAN PABLO, PH. 1	2H3	6/30/2013	-	134,053	1,012,797	-	**1,146,850**	WP 4-102	WP 4-206
48	30842277	23630	VALVE AUTO - CRYSTAL RANCH, PH. 1	2H3	6/30/2013	-	194,241	1,467,532	-	**1,661,773**	WP 4-104	WP 4-236
49	30842326	23631	VALVE AUTO - WALNUT AVE, PH. 1	2H3	6/30/2013	-	133,041	1,005,152	-	**1,138,193**	WP 4-106	WP 4-237
50	30842286	23632	VALVE AUTO - FOLEY'S RANCH CROSSOVER, PH. 1	2H3	9/30/2013	-	17,362	876,480	-	**893,842**	WP 4-108	WP 4-238
51	30842324	23633	VALVE AUTO - VARGAS CROSSOVER, PH. 1	2H3	9/30/2013	-	18,559	936,887	-	**955,446**	WP 4-110	WP 4-239
52	30842295	23634	VALVE AUTO - IRVINGTON, PH. 1	2H3	9/30/2013	-	79,506	4,013,688	-	**4,093,194**	WP 4-112	WP 4-240
53	30842317	23972	VALVE AUTO - SHERIDAN RD, PH. 1	2H3	9/30/2013	-	7,027	354,757	-	**361,784**	WP 4-115	WP 4-241
54	30842300	23635	VALVE AUTO - LIVERMORE & AIRWAY, PH. 1	2H3	9/30/2013	-	19,827	1,000,928	-	**1,020,755**	WP 4-117	WP 4-242
55	30842279	23636	VALVE AUTO - DALTON CROSSOVER, PH. 1	2H3	9/30/2013	-	21,593	1,090,080	-	**1,111,673**	WP 4-119	WP 4-243
56	30842301	23637	VALVE AUTO - LIVERMORE JUNCTION, PH. 1	2H3	9/30/2013	-	14,992	756,811	-	**771,803**	WP 4-121	WP 4-244
57	30842320	23638	VALVE AUTO - THORTON AVE, PH. 1	2H3	9/30/2013	-	29,694	1,499,042	-	**1,528,736**	WP 4-123	WP 4-245
58	30842268	23645	VALVE AUTO - ALVARADO, PH. 1	2H3	9/30/2013	-	15,383	776,561	-	**791,944**	WP 4-125	WP 4-246
59	30842329	23647	VALVE AUTO - WINTON AVE, PH. 1	2H3	12/31/2013	-	-	582,788	52,166	**634,954**	WP 4-127	WP 4-247
60	30842285	23649	VALVE AUTO - FAIRWAY AVE, PH. 1	2H3	12/31/2013	-	-	727,579	65,126	**792,705**	WP 4-129	WP 4-248
61	30842260	23651	VALVE AUTO - 51ST AVENUE, PH. 1	2H3	12/31/2013	-	-	2,290,229	204,999	**2,495,228**	WP 4-131	WP 4-249
62	30842259	23655	VALVE AUTO - 4TH & JEFFERSON, PH. 1	2H3	12/31/2013	-	-	2,042,581	182,832	**2,225,413**	WP 4-133	WP 4-250
63	30842273	23657	VALVE AUTO - BRENTWOOD TERMINAL, PH. 1	2H3	12/31/2013	-	-	4,328,642	387,458	**4,716,100**	WP 4-136	WP 4-251
64	30842296	23659	VALVE AUTO - LAKES VALVE LOT, PH. 1	2H3	12/31/2013	-	-	746,147	66,788	**812,935**	WP 4-139	WP 4-252
65	30842272	23661	VALVE AUTO - BIXLER RD, PH. 1	2H3	12/31/2013	-	-	1,429,014	127,911	**1,556,925**	WP 4-141	WP 4-253
66	30842308	23663	VALVE AUTO - PALM TRACT, PH. 1	2H3	12/31/2013	-	-	327,672	29,330	**357,002**	WP 4-143	WP 4-254
67	30842258	23665	VALVE AUTO - 24TH & 20TH AVE, PH. 1	2H3	3/31/2014	-	-	994,821	1,414,145	**2,408,966**	WP 4-145	WP 4-255
68	30842330	23669	VALVE AUTO - YOLO CAUSWAY BLVD. TIE, PH. 1	2H3	3/31/2014	-	-	720,293	1,023,902	**1,744,195**	WP 4-147	WP 4-256
69	30842307	23673	VALVE AUTO - N SAC UGND HLDR, PH. 1	2H3	3/31/2014	-	-	772,922	1,098,715	**1,871,637**	WP 4-149	WP 4-257
70	30842313	23675	VALVE AUTO - SAC GAS LOAD CENTER, PH. 1	2H3	3/31/2014	-	-	455,793	647,913	**1,103,706**	WP 4-151	WP 4-258
71	30842309	23679	VALVE AUTO - PARAMOUNT COURT, PH. 1	2H3	3/31/2014	-	-	705,071	1,002,264	**1,707,335**	WP 4-154	WP 4-259
72	30842322	23674	VALVE AUTO - VALERO REFINERY TAP, PH. 1	2H3	3/31/2014	-	-	840,734	1,195,110	**2,035,844**	WP 4-156	WP 4-260
73	30842281	23672	VALVE AUTO - EAST FAIRFIELD CROSSOVER, PH. 1	2H3	3/31/2014	-	-	495,353	704,148	**1,199,501**	WP 4-158	WP 4-261
74	30842284	23670	VALVE AUTO - FAIRFIELD CROSSOVER, PH. 1	2H3	3/31/2014	-	-	676,185	961,202	**1,637,387**	WP 4-160	WP 4-262
75	30842275	23668	VALVE AUTO - CORDELIA, PH. 1	2H3	6/30/2014	-	-	248,522	1,876,016	**2,124,538**	WP 4-163	WP 4-263
76	30842311	23667	VALVE AUTO - RIPON-MODESTO, PH. 1	2H3	6/30/2014	-	-	108,371	818,059	**926,430**	WP 4-166	WP 4-264
77	30842265	23664	VALVE AUTO - AIRPORT & YOSEMITE, PH. 1	2H3	6/30/2014	-	-	218,027	1,645,817	**1,863,844**	WP 4-168	WP 4-265
78	30842263	23662	VALVE AUTO - AIRPORT & FRENCH CAMP, PH. 1	2H3	6/30/2014	-	-	101,547	766,545	**868,092**	WP 4-170	WP 4-266
79	30842264	23660	VALVE AUTO - AIRPORT & SORONA, PH. 1	2H3	6/30/2014	-	-	101,841	768,764	**870,605**	WP 4-172	WP 4-267
80	30842327	23658	VALVE AUTO - WEST LANE & HAMMERTOWN, PH. 1	2H3	6/30/2014	-	-	214,528	1,619,405	**1,833,933**	WP 4-174	WP 4-268

SB_GT&S_0354092

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 4, Valve Automation

Table 2
Capital Expenditures by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
81	30842262	23656	VALVE AUTO - 8 MILE PLS, PH. 1	2H3	6/30/2014	-	-	75,134	567,165	**642,299**	WP 4-176	WP 4-269
82	30842298	23654	VALVE AUTO - LAS VINAS STA, PH. 1	2H3	6/30/2014	-	-	54,332	410,139	**464,471**	WP 4-178	WP 4-270
83	30841471	23652	VALVE AUTO - UNION AVE METER REG STA, PH. 1	2H3	9/30/2014	-	-	14,072	709,761	**723,833**	WP 4-180	WP 4-271
84	30841470	23650	VALVE AUTO - GOSFORD RD MTR STA, PH. 1	2H3	9/30/2014	-	-	18,429	929,516	**947,945**	WP 4-182	WP 4-272
85	30841469	23648	VALVE AUTO - BAKERSFIELD TAP, PH. 1	2H3	9/30/2014	-	-	17,210	868,077	**885,287**	WP 4-184	WP 4-273
86	30841958	23973	VALVE AUTO - CUMMINGS CREEK, PH. 1	2H3	9/30/2014	-	-	3,606	181,870	**185,476**	WP 4-186	WP 4-274
87	30842321	23974	VALVE AUTO - TOMPKINS HILL, PH. 1	2H3	9/30/2014	-	-	13,581	685,036	**698,617**	WP 4-188	WP 4-275
88	30841467	23646	VALVE AUTO - 2AX PLS, PH. 1	2H3	9/30/2014	-	-	7,123	359,293	**366,416**	WP 4-190	WP 4-276
89	30841466	23644	VALVE AUTO - MOJAVE RIVER CROSSING, PH. 1	2H3	9/30/2014	-	-	22,188	1,119,151	**1,141,339**	WP 4-192	WP 4-277
90	30842294	23975	VALVE AUTO - INSTALL FLOW METERING, PH. 1	2H3	9/30/2014	31,348	3,919,473	5,270,294	3,239,615	**12,460,730**	WP 4-194	n/a
91	30864263	24923	VALVE AUTO - SCADA ENHANCEMENTS	2H3	12/31/2014	40,000	240,000	240,000	240,000	**760,000**	WP 4-196	n/a
92			**Total MAT 2H3 - Imp Plan Valve Automation**			**13,686,700**	**37,599,704**	**48,714,483**	**25,968,238**	**125,969,125**		
93												
94			**Total Valve Automation Capital Projects**			**13,686,700**	**39,548,367**	**53,324,954**	**25,968,238**	**132,528,258**		

Pacific Gas and Electric Company
Implementation Plan
Workpapers Supporting Chapter 4, Valve Automation

Table 3
Expenses by Maintenance Activity Type (MAT)

Line No	Order	PSRS Id	Order Description	MAT	Operative Date	2011	2012	2013	2014	Total	Workpaper Reference	Map Reference
1	41474104	23355	VALVE AUTO SCADA ENHANCEMENTS	KE4	12/31/2014	803,206	1,830,559	1,810,423	2,207,585	**6,651,773**	WP 4-279	n/a
2	41482824	24155	VALVE AUTO M&O, PH. 1	KE4	12/31/2014	-	750,817	1,298,118	1,606,063	**3,654,998**	WP 4-281	n/a
3			**Total MAT KE4 - Imp Plan Station Other**			**803,206**	**2,581,376**	**3,108,541**	**3,813,648**	**10,306,771**		
4												
5	41416677	22725	Imp Plan - Valve Planning Expense	KE4	12/31/2011	800,000	-	-	-	**800,000**	WP 4-283	n/a
6			**Total MAT KEX - Imp Plan Pipeline Other**			**800,000**	**-**	**-**	**-**	**800,000**		
7												
8			**Total Valve Automation Expense Projects**			**1,603,206**	**2,581,376**	**3,108,541**	**3,813,648**	**11,106,771**		

Exhibit C

Statement of PG&E's Presently Effective Gas Rates

Pacific Gas and Electric Company

Gas RateFinder

August 2011 Volume 40-G, No. 8

The *Gas RateFinder* is produced by the Pacific Gas and Electric Company Analysis and Rates Department as a quick reference to most PG&E gas rates, for both PG&E employees and customers. It does not replace tariff sheets.

This *Gas RateFinder* contains core and noncore gas price changes for the month of **August 2011.**

To view the current Gas RateFinder and 2010/2009/2008 editions, please visit PG&E's Internet site at: http://www.pge.com/tariffs (Select #17)

Questions about PG&E's rates or tariffs can be E-mailed to: Tmail@pge.com, or by phone by calling 1-800-743-5000.

Contents

[*Rates Change Monthly]

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I - Core Gas Rates

Residential Gas Rates

The residential gas rates below are effective August 1, 2011, through August 31, 2011.

	SCHEDULES G-1, GM, GS, GT		SCHEDULES GL-1, GML, GSL, GTL	
	BASELINE	EXCESS	BASELINE	EXCESS
Procurement Charge (per therm)	$0.64931	$0.64931	$0.64931	$0.64931
Transportation Charge (per therm)	$0.48036	$0.76858	$0.48036	$0.76858
Care Discount	n/a	n/a	-$0.22593	-$0.28358
Total Residential Schedule Charge[1/]	$1.12967	$1.41789	$0.90374	$1.13431
Schedule G-PPPS (Public Purpose Program Surcharge)[1/] (per therm)	$0.08400	$0.08400	$0.05959	$0.05959
Minimum Transportation Charge (G-1 Only)[2/] (per day)	$0.09863			
Discount (per day)				
GS & GSL only (per dwelling unit)	$0.20900		$0.20900	
GT & GTL only (per installed space)	$0.48200		$0.48200	
Minimum Average Rate Limiter (per therm)				
Eliminated August 1, 2010, due to BCAP D. 10-06-035	--		--	

[1/]Schedule G-PPPS needs to be added to the Total Charge for bill calculation. See Schedule G-PPPS.
[2/]The Transportation Charge will be no less than the Minimum Transportation Charge. The Minimum Transportation Charge does not apply to submetered tenants of master-metered customers served under gas Rate Schedules GS and GT.

Baseline Territories and Quantities

WINTER (November 1 – March 31)					SUMMER (April 1 - October 31)				
TERRITORY	INDIVIDUALLY METERED		MASTER METERED (GM & GML only)		TERRITORY	INDIVIDUALLY METERED		MASTER METERED (GM & GML only)	
	Monthly	Daily	Monthly	Daily		Monthly	Daily	Monthly	Daily
P	66	2.18	30	0.99	P	15	0.49	11	0.36
Q	62	2.05	25	0.83	Q	21	0.69	18	0.59
R	56	1.85	52	1.72	R	15	0.49	15	0.49
S	59	1.95	23	0.76	S	15	0.49	11	0.36
T	54	1.79	35	1.16	T	21	0.69	18	0.59
V	52	1.72	35	1.16	V	22	0.72	17	0.56
W	54	1.79	30	0.99	W	15	0.49	10	0.33
X	62	2.05	25	0.83	X	19	0.62	12	0.39
Y	80	2.64	33	1.09	Y	27	0.88	19	0.62

To calculate bills use daily quantity (monthly provided for information purposes only).

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Residential Natural Gas Vehicle Rates

The residential natural gas vehicle rates below are effective August 1, 2011, through August 31, 2011.

	SCHEDULE G1-NGV	SCHEDULE GL1-NGV
Customer Charge (per day)	**$0.41425**	**$0.33140**
Procurement Charge (per therm)	**$0.53916**	**$0.53916**
Transportation Charge (per therm)	**$0.24403**	**$0.24403**
Care Discount	n/a	**-$0.15664**
Total G1-NGV or GL1-NGV Schedule Charge[1/]	**$0.78319**	**$0.62655**
Schedule G-PPPS (Public Purpose Program Surcharge)[1/] (per therm)	**$0.08400**	**$0.05959**

[1/] Schedule G-PPPS needs to be added to the Total Charge for bill calculation. See Schedule G-PPPS.

This rate schedule applies to natural gas service to Core End-Use Customers on PG&E's Transmission and/or Distribution Systems. Service on this schedule is an option to those customers for whom Schedule G-1 or GL-1 applies** and is for residential use where a Natural Gas Vehicle (NGV) has been leased or purchased and a home refueling appliance (HRA) has been installed for the sole purpose of compressing natural gas for use as a motor-vehicle fuel for the personal vehicle(s) owned or leased by the customer served under this rate schedule. Compression of natural gas to the pressure required for its use as motor-vehicle fuel will be performed by the Customer's equipment at the Customer's designated premises only.

Schedule G1-NGV and GL1-NGV applies everywhere within PG&E's natural gas Service Territory. Customers are responsible for federal and state taxes applicable to fuels for vehicular use.

Certification

In order to receive service under this rate schedule, customers must provide a Natural Gas Home Refueling Appliance Certification (Form No. 79-1047) to PG&E.

Surcharges

Customers served under this schedule in conjunction with Schedule G-CT, or in conjunction with noncore service, are subject to a franchise fee surcharge under Schedule G-SUR for gas volumes purchased from parties other than PG&E and transported by PG&E. Customers served under this schedule are subject to a gas Public Purpose Program (PPP) Surcharge under Schedule G-PPPS.

Alternate Procurement Service

Customers may procure gas supply from a party other than PG&E by taking service on this schedule in conjunction with Schedule G-CT – Core Gas Aggregation Service. Customers who procure their own gas supply will not pay the Procurement Charge component on this rate schedule shown above and will be subject to the applicable rates specified in Schedule G-CT.

**Schedule GL-1 applies to applicants who qualify for California Rates for Energy (CARE) under the eligibility and certification criteria set forth in Rules 19.1, 19.2, or 19.3.

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Core Commercial Gas Rates

Rates below are effective August 1, 2011, through August 31, 2011.

Small Commercial: Schedule G-NR1 (Usage less than 20,800 therms per month)*

	HIGHEST AVERAGE DAILY USAGE**				
	0 - 5.0 THERMS	5.1 - 16.0 THERMS	16.1 - 41.0 THERMS	41.1 - 123.0 THERMS	123.1 & UP THERMS
Customer Charge (per day)	$0.27048	$0.52106	$0.95482	$1.66489	$2.14936
		PER THERM			
		SUMMER		WINTER	
		FIRST 4,000 THERMS	EXCESS THERMS	FIRST 4,000 THERMS	EXCESS THERMS
Procurement Charge (per therm)		$0.56602	$0.56602	$0.56602	$0.56602
Transportation Charge (per therm)		$0.30289	$0.11883	$0.36983	$0.14509
Total G-NR1 Schedule Charge1/		$0.86891	$0.68485	$0.93585	$0.71111
Schedule G-PPPS (Public Purpose Program Surcharge)1/ (per therm)		$0.05078	$0.05078	$0.05078	$0.05078

*Excluding months during which usage is less than 200 therms.
**Based on customer's highest Average Daily Usage (ADU) determined from among the billing periods occurring within the last twelve months, including current billing period. PG&E calculates the ADU for each billing period by dividing the total usage by the number of days in the billing period.

Large Commercial: Schedule G-NR2 (Usage greater than 20,800 therms per month)*

	PER DAY	PER THERM			
		SUMMER		WINTER	
		FIRST 4,000 THERMS	EXCESS THERMS	FIRST 4,000 THERMS	EXCESS THERMS
Customer Charge	$4.95518				
Procurement Charge		$0.46801	$0.46801	$0.46801	$0.46801
Transportation Charge		$0.30289	$0.11883	$0.36983	$0.14509
Total G-NR2 Schedule Charge1/		$0.77090	$0.58684	$0.83784	$0.61310
Schedule G-PPPS (Public Purpose Program Surcharge)1/		$0.09366	$0.09366	$0.09366	$0.09366

*Excluding months during which usage is less than 200 therms.

1/Schedule G-PPPS needs to be added to the Total Charge for bill calculation. Prior to April 1, 2005, the transportation rate included the PPP surcharge mandated by state. Effective April 1, 2005, gas PPP surcharges are removed from gas transportation rates. See Schedule G-PPPS for details and CARE rate.

G-NR1 and G-NR2 Seasons:
Summer: April 1 through Oct. 31
Winter: November 1 through March 31

Core Gas Aggregation Rates

Core Gas Aggregation Service: Schedule G-CT

Schedule G-CT applies to transportation of natural gas for Core End-Use Customers who aggregate their gas volumes and who obtain natural gas supply service from a source other than PG&E. The provisions of Schedule G-CT apply to Core End-Use Customers and to the party who supplies them with natural gas and provides or obtains services necessary to deliver such gas to PG&E's Distribution System. Rule 23 (Tariff Book) also sets forth terms and conditions applicable to Core Gas Aggregation Service.

A group of Core End-Use Customers who aggregate their gas volumes comprise a Core Transport Group (Group). The minimum aggregate gas volume for a Group is 12,000 decatherms per year. The Customer must designate a Core Transport Agent (CTA), who is responsible for providing gas aggregation services to Customers in the Group as described in Rule 23. Aggregation of multiple loads at a single facility or aggregation of loads at multiple facilities shall not change the otherwise-applicable rate schedule for a specific facility. Customers electing service under this schedule must request such service for one hundred percent of the core load served by the meter. Schedule G-CT must be taken in conjunction with a core rate schedule.

Core volumes are eligible for service under this schedule, whether or not noncore volumes are also delivered to the same premises. However, core volumes cannot be aggregated with noncore volumes in order to meet the minimum therm requirement for noncore service. Service to core volumes associated with noncore volumes under this schedule applies to all core volumes on the noncore premises.

CTAs, on behalf of a Group, may receive service on PG&E's Backbone Transmission System by utilizing Schedules G-AFT, G-SFT, G-AA, G-NFT, or G-NAA.

Rates

Customers taking service under Schedule G-CT will receive and pay for service under their otherwise-applicable core rate schedule in addition to the rate shown below, except that Customers who procure their own gas supply do not pay the Procurement Charge specified on their otherwise-applicable core rate schedule.

Additional Charges

Pursuant to Schedule G-SUR, Customers will be subject to a franchise fee surcharge for gas volumes purchased from parties other than PG&E and transported by PG&E. Customers are also responsible for any applicable costs, taxes and / or fees incurred by PG&E in receiving gas to be delivered to such Customers.

See Schedule G-CT for further details.

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Natural Gas Vehicle Rates

The Schedule G-NGV1 and G-NGV2 rates shown below are effective August 1, 2011, through August 31, 2011.

Natural Gas Service For Compression On Customer's Premises: Schedule G-NGV1 (Rates change monthly)

Schedule G-NGV1 applies to the sale of uncompressed natural gas for the sole purpose of compressing it for use as a motor-vehicle fuel. Compression of natural gas to the pressure required for its use as motor-vehicle fuel will be performed by the Customer's equipment at the Customer's designated premises only.

	PER DAY	PER THERM
Customer Charge	**$0.44121**	
Procurement Charge		**$0.46364**
Transportation Charge		**$0.11529**
Total G-NGV1 Schedule Charge		**$0.57893**
Schedule G-PPPS (Public Purpose Program Surcharge)[1/]		**$0.02674**

Note: The gas procurement charge and total rates generally change on the 1st day of each month. (Transportation rates do not change monthly.) See Schedule G-NGV1 for further details.

Compressed Natural Gas Service on PG&E's Premises: Schedule G-NGV2 (Rates change monthly)

Schedule G-NGV2 applies to the sale of compressed natural gas (CNG) at PG&E-owned natural gas fueling stations to customers who use CNG as a motor fuel.

	PER MONTH	PER THERM
Procurement Charge		**$0.46364**
Transportation Charge		**$1.36774**
Total G-NGV2 Schedule Charge		**$1.83138**
Per Gasoline Gallon Equivalent		**$2.33684**
Schedule G-PPPS (Public Purpose Program Surcharge)[1/]		**$0.02674**

Note: The gas procurement charge and total rates generally change on the 5th business day of each month. (Transportation rates do not change monthly.) See Schedule G-NGV2 for further details.

[1/]Schedule G-PPPS needs to be added to the Total Charge for bill calculation.

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Noncore Natural Gas Service for Compression on Customers' Premises: Schedule G-NGV4

Schedule G-NGV4 applies to the transportation of natural gas to customer-owned natural gas vehicle fueling stations on PG&E's Backbone, Local Transmission and / or Distribution Systems. To qualify for service a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential customer must have maintained an average monthly use through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. Customers must procure gas supply from a supplier other than PG&E.

Rates

The applicable Customer Access Charges and Distribution Level Transportation Rate below is based on the Customer's Average Monthly Usage, as defined in Gas Rule 1 (see Tariff Book, Gas Rule 1). Usage through multiple noncore gas meters on a single premise will be combined to determine Average Monthly Usage.

Customer Access Charge

The applicable Per-Day Customer Access Charge is multiplied by the number of days in the billing period.

Average Monthly Use (therms)	Per Day
0 to 5,000 therms	$1.78652
5,001 to 10,000 therms	$5.32175
10,001 to 50,000 therms	$9.90477
50,001 to 200,000 therms	$12.99912
200,001 to 1,000,000 therms	$18.86038
1,000,001 therms and above	$159.98499

Transportation Charge

A customer will pay one of the following rates for gas delivered in the current billing month.

Backbone-Level Rate:

Applies to Backbone Level End-Use Customers as defined in Rule 1.

Transmission-Level Rate:

Applies to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi).

Distribution-Level Rate:

Applies to Customers served from PG&E gas facilities that have a maximum operating pressure of sixty pounds per square inch (60 psi) or less. The Tier 5 rate is equal to the Transmission-Level Rate.

Backbone (per therm)	$0.00600				
Transmission (per therm)	$0.02674				
Distribution (per therm)	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
Average Monthly Use	0-20,833 therms	20,834-49,999 therms	50,000-166,666 therms	166,667-249,999 therms	250,000 and above*
Summer	$0.15818	$0.11042	$0.10067	$0.09304	$0.02674
Winter	$0.20429	$0.13982	$0.12665	$0.11635	$0.02674

Summer Season: April 1 through October 31 Winter Season: November 1 through March 31

Customers on this schedule are subject to Schedule G-PPPS, a gas Public Purpose Program Surcharge, as shown below. See Schedule G-PPPS for details.

Public Purpose Program Surcharge (per therm)

Distribution/Transmission
$0.02674

Additional Charges

Customers may pay a franchise fee surcharge for gas volumes transported by PG&E (See Schedule G-SUR for details.) Customers are responsible for any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. See Schedule G-NGV4 for details.

Gas Public Purpose Program Surcharge

The Schedule G-PPPS Surcharge rates shown below are effective January 1, 2011.

Public Purpose Program Surcharge: Schedule G-PPPS

Pursuant to Public Utility (PU) Code Sections 89-0900, this schedule applies a gas Public Purpose Program (PPP) surcharge to gas transportation volumes under the rate schedules specified below. The gas PPP surcharge is collected to fund gas energy efficiency and low-income energy efficiency programs, the California Alternate Rates for Energy (CARE) low-income assistant program, and public interest research and development. Under PU Code Section 896, certain customers are exempt from the gas PPP surcharge as described in the Exempt Customer section, below.

Rates

The following surcharges apply to natural gas service for eligible Core and Noncore End-Use Customers.

CUSTOMER CLASS (RATE SCHEDULE):	PER THERM (NON-CARE)	PER THERM (CARE)
Residential: (G-1, G1-NGV, GM, GS, GT, GL-1, GL1-NGV, GML, GSL, and GTL)	**$0.08400**	**$0.05959**
Small Commercial: (G-NR1)	**$0.05078**	**$0.02637**
Large Commercial: (G-NR2)	**$0.09366**	**$0.06925**
Natural Gas Vehicle: (G-NGV1/G-NGV2/G-NGV4)	**$0.02674**	**n/a**
Industrial: (G-NT - Distribution)	**$0.04314**	**n/a**
Industrial: (G-NT – Backbone/Transmission)	**$0.03489**	**n/a**
Liquid Natural Gas (G-LNG)	**$0.02674**	**n/a**

Exempt Customers

In accordance with PU Code Section 896, certain customers are exempt from Schedule G-PPPS. These include:

a. All gas consumed by customer's served under Schedules G-EG and G-WSL;
b. All gas consumed by Enhanced Oil Recovery (EOR) facilities;
c. All gas consumed by customers in which the State of California is prohibited from taxing under the United States Constitution or the California Constitution, consistent with California Energy Resources Surcharge Regulations 2315 and 2316, as described in Publication No. 11 issued by the California State Board of Equalization (BOE), which include:

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Public Purpose Program Surcharge (cont'd)

1. The United States, its unincorporated agencies and instrumentalities;
2. Any incorporated agency of instrumentality of the United States wholly owned by either the United States or by a corporation wholly owned by the United States;
3. The American National Red Cross, its chapters and branches;
4. Insurance companies, including title insurance companies, subject to taxation under California Constitution, Article XIII, Section 28, or it's successor;
5. Enrolled Indians purchasing and consuming natural gas on Indian reservations; and
6. Federal Credit unions organized in accordance with the provisions of the Federal Credit Union Act.

Exempt Customer Bill Adjustments:

PG&E will annually review its customer accounts and make appropriate bill adjustments to return any surcharge amounts received from exempt customers, plus applicable interest, within 30 days after identification of such exempt customers, unless previously refunded from the State Treasury. PG&E will inform BOE of any refunds issued to customers.

See Schedule G-PPPS for further details.

II - Noncore Gas Rates

Gas Franchise Fee Surcharge

The Schedule G-SUR Franchise Fee Surcharge rate shown below is effective August 1, 2011, through August 31, 2011.

Customer-Procured Gas Franchise Fee Surcharge: Schedule G-SUR (Rate changes monthly)

Pursuant to California State Senate Bill No. 278 (1993), Schedule G-SUR applies to all gas volumes procured by Customers from third-party entities and transported by PG&E with the following exceptions:

a) the State of California or a political subdivision thereof;
b) one gas utility transporting gas for end-use in its Commission-designated service area through another utility's service area;
c) a utility transporting its own gas through its own gas transmission and distribution system for purposes of generating electricity or for use in its own operations;
d) cogeneration Customers, for that quantity of natural gas billed under Schedule G-EG.

Surcharge Recovery
The surcharge will be shown on the Customer's monthly bill based on volumes procured by the Customer from a third-party gas supplier and transported by PG&E (metered usage).

Rates
The G-SUR surcharge changes on a monthly basis and is comprised of the following components:

	PER THERM
a. the monthly core Weighted Average Cost of Gas (WACOG) , exclusive of Storage Costs, Franchise Fees and Uncollectibles, which is multiplied by	**$0.41191**
b. the Franchise Fee factor* adopted in PG&E's most recent General Rate Case, which is	**0.009886**
The Schedule G-SUR Franchise Fee Surcharge is effective August 1, 2011, through August 31, 2011.	**$0.00407**

*Does not include Uncollectibles factor of 0.003145.

See Schedule G-SUR for further details.

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III - Gas Transportation Rates

Gas Transportation Service to Noncore End-Use Customers: Schedule G-NT

Schedule G-NT applies to the transportation of natural gas to Noncore End-Use Customers on PG&E's Backbone, Local Transmission and / or Distribution Systems. To qualify, a Customer must be classified as a Noncore End-Use Customer, as defined in Rule 1. To initially qualify for noncore status, a non-residential customer must have maintained an average monthly use through a single meter, in excess of 20,800 therms during the previous twelve (12) months, excluding those months during which usage was 200 therms or less. Customers must procure gas supply from a supplier other than PG&E.

Rates

The applicable Customer Access Charges and Distribution Level Transportation Rate below is based on the Customer's Average Monthly Usage, as defined in Gas Rule 1 (see Tariff Book, Gas Rule 1). Usage through multiple noncore gas meters on a single premise will be combined to determine Average Monthly Usage.

Customer Access Charge

The applicable Per-Day Customer Access Charge is multiplied by the number of days in the billing period.

AVERAGE MONTHLY USE (THERMS)	PER DAY
0 to 5,000 therms	$1.78652
5,001 to 10,000 therms	$5.32175
10,001 to 50,000 therms	$9.90477
50,001 to 200,000 therms	$12.99912
200,001 to 1,000,000 therms	$18.86038
1,000,001 therms and above	$159.98499

Transportation Charge

A customer will pay one of the following rates for gas delivered in the current billing month.

Transmission-Level Rate:
Apply to Customers served directly from PG&E gas facilities that have a maximum operating pressure greater than sixty pounds per square inch (60 psi).

Distribution-Level Rate:
Apply to Customers served from PG&E gas facilities that have a maximum operating pressure of sixty pounds per square inch (60 psi) or less. The Tier 5 rate is equal to the Transmission-Level Rate.

Backbone (per therm)	$0.00600				
Transmission (per therm)	$0.03282				
Distribution (per therm)	Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
Average Monthly Use	0-20,833 therms	20,834-49,999 therms	50,000-166,666 therms	166,667-249,999 therms	250,000 and above*
Summer	$0.15818	$0.11042	$0.10067	$0.09304	$0.03282
Winter	$0.20429	$0.13982	$0.12665	$0.11635	$0.03282

Summer Season: April 1 through October 31 Winter Season: November 1 through March 31

Customers on this schedule are subject to Schedule G-PPPS, a gas Public Purpose Program Surcharge, as shown below. See Schedule G-PPPS for details.

Public Purpose Program Surcharge (per therm)

BACKBONE/TRANSMISSION	DISTRIBUTION
$0.03489	$0.04314

Additional Charges

Customers may pay a franchise fee surcharge for gas volumes transported by PG&E (See Schedule G-SUR for details.) Customers are responsible for any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. See Schedule G-NT for further details.

Gas Transportation Service to Electric Generation: Schedule G-EG

Schedule G-EG applies to the transportation of natural gas used in: (a) electric generation plants served directly from PG&E gas facilities that have a maximum operation pressure greater than sixty pounds per square inch (60 psi); (b) all Cogeneration facilities that meet the efficiency requirements specified in the California Public Utilities Code Section 216.6; and (c) solar electric generation plants, defined herein.

This schedule does not apply to gas transported to non-electric generation loads.
Customers on Schedule G-EG with generating capacity 500 kilowatts or larger, or with gas usage in excess of 250,000 therms per year must procure gas supply from a third-party gas supplier, not from a Core Procurement Group.

Certain noncore customers served under this rate schedule may be restricted from converting to a core rate schedule. See Rule 12 (in Tariff Book) for details on core and noncore reclassification.

Rates

The following charges apply to this schedule. They do not include charges for service on PG&E's Backbone Transmission System.

Customer Access Charge

The applicable Per-Day Customer Access Charges is based on the Customer's Average Monthly Usage, as defined in Gas Rule 1 (see Tariff Book, Gas Rule 1). Usage through multiple noncore gas meters on a single premise will be combined to determine Average Monthly Usage. Customers taking service under this schedule who also receive service under other noncore rate schedules at the same premises will be charged a single Customer Access Charge under this schedule.

AVERAGE MONTHLY USE (THERMS)	PER DAY
0 to 5,000 therms	$1.78652
5,001 to 10,000 therms	$5.32175
10,001 to 50,000 therms	$9.90477
50,001 to 200,000 therms	$12.99912
200,001 to 1,000,000 therms	$18.86038
1,000,001 therms and above	$159.98499

Transportation Charge

	BACKBONE	ALL OTHER CUSTOMERS
Transportation Charge (per therm)	$0.00725	$0.02799

Customers may be required to pay a franchise fee surcharge for gas volumes transported by PG&E. (See Schedule G-SUR for details).

Additional Charges

Customers are responsible for any other applicable costs, taxes, and/or fees incurred by PG&E in taking delivery of gas supplied from a source other than PG&E from intra- or interstate sources.

See Schedule G-EG for further details.

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Gas Transportation to Wholesale/Resale Customers and Gas Balancing Service

Gas Transportation Service to Wholesale/Resale Customers: Schedule G-WSL

Schedule G-WSL applies to the transportation of natural gas for resale. Schedule G-WSL is available to the Customers listed below, and any new wholesale Customer. Customers must procure gas supply from a supplier other than PG&E.

Rates
Customers pay a Customer Access Charge and a Transportation Charge.

	Palo Alto	Coalinga	West Coast Gas-Mather		Island Energy	Alpine Natural Gas	West Coast Gas-Castle
Customer Access Charge (per day)	$138.97907	$41.68274	$22.12767		$28.24142	$9.42444	$24.21337
	Trans.	**Trans.**	**Trans.**	**Dist.**	**Trans.**	**Trans.**	**Dist.**
Transportation Charge (per therm)	$0.02514	$0.02514	$0.02514	$0.12256	$0.02514	$0.02514	$0.09871

Existing Wholesale Customers will have a one-time option prior to June 1, 2011, to subscribe, on behalf of their core Customers, for firm capacity on the Redwood to on-system and Baja to on-system paths as specified below. Capacity will be offered only for the core portion of the Customer's load. See Rate Schedule G-WSL for further details.

Customer	Redwood (MDth)	Baja – Annual (MDth)	Baja – Seasonal (MDth)
Alpine	0.098	0.056	0.052
Coalinga	0.552	0.316	0.291
Island Energy	0.064	0.037	0.034
Palo Alto	5.898	3.372	3.110
West Coast Gas (Castle)	0.051	0.029	0.027
West Coast Gas (Mather)	0.171	0.098	0.090

Additional Charges
Customers are responsible for any other applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.
See Schedule G-WSL for further details.

Gas Balancing Service for Intrastate Transportation Customers: Schedule G-BAL

Under Schedule G-BAL, PG&E will calculate, maintain and carry imbalances; provide incentives for Customers to avoid and minimize imbalances, facilitate elimination of imbalances; and cash out imbalances. Schedule G-BAL applies to PG&E's Core Procurement Department for transactions on behalf of PG&E's core procurement Customers, and to all Customers taking service under Schedules G-CT (or other core rate schedule(s) where procurement service is provided by a third party), to Schedules G-NT, G-EG, G-NGV4, G-WSL, G-AFT, G-SFT, G-NFT, G-AA, G-NAA, G-AFTOFF, G-AAOFF, G-NFTOFF, G-NAAOFF, G-PARK, and G-LEND.
See Schedule G-BAL for further details.

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Firm Transportation On-System Rates

Annual Firm Transportation On-System: Schedule G-AFT

Schedule G-AFT applies to firm gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off- System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under G-AFT is available only for the transportation of natural gas within PG&E's service territory on the paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AFT are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities, or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)

Any Delivery Point(s) to which gas is transported under this rate schedule must be an On- System Delivery Point.

Rates

The Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, as specified in the Customer's Service Agreement.

Reservation Charge

The reservation charge is the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the Customer's Service Agreement. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

PATH	RESERVATION RATE (PER DECATHERM PER MONTH)	
	MFV Rates	SFV Rates
Redwood to On-System	$5.4087	$8.3095
Redwood to On-System (Core Procurement Groups only)	$4.7466	$6.5162
Baja to On-System	$5.8930	$9.0536
Baja to On-System (Core Procurement Groups only)	$5.2811	$7.2499
Silverado to On-System (including Core Procurement Groups)	$3.2679	$4.8056
Mission to On-System (including Core Procurement Groups)	$3.2679	$4.8056

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Annual Firm Transportation On-System: Schedule G-AFT (cont'd)

Usage Charge
The Usage Charge is equal to the applicable usage rate for the Customer's contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

PATH	USAGE RATE (PER DECATHERM)	
	MFV Rates	SFV Rates
Redwood to On-System	$0.1038	$0.0084
Redwood to On-System (Core Procurement Groups only)	$0.0684	$0.0102
Baja to On-System	$0.1129	$0.0089
Baja to On-System (Core Procurement Groups only)	$0.0758	$0.0111
Silverado to On-System (including Core Procurement Groups)	$0.0554	$0.0049
Mission to On-System (including Core Procurement Groups)	$0.0554	$0.0049
Mission to On-System Storage Withdrawals (Conversion option from Firm On-System Redwood or Baja Path only)	$0.0000	$0.0000

Additional Charges
The Customer is responsible for payment of any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-AFT for further details.

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Firm Transportation Off-System Rates

Annual Firm Transportation Off-System: Schedule G-AFTOFF

Schedule G-AFTOFF applies to firm gas transportation service on PG&E's Backbone Transmission System to the Off-System Delivery Points. Schedule G-AFTOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below for off-system deliveries. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AFTOFF are as follows:

PATH	RECEIPT POINT(S)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Firm Off-System Delivery Points

Kern River Station to Southern California Gas Company
Fremont Peak to Kern River Gas Transmission

Backhaul Off-System Points

All off-system interconnection points are available as backhaul delivery points under this schedule if the upstream pipeline accepts backhaul nominations. Backhaul service is limited to the quantities of gas being delivered from the upstream pipeline.

Alternative Delivery Points

If the Customer elects the Modified Fixed Variable (MFV) rate structure under Schedule G-AFTOFF, the Delivery Point under this schedule shall be limited to a Firm Off-System Delivery Point. If the Customer elects the Straight Fixed Variable (SFV) rate structure under G-AFTOFF, the Customer may specify an On-System Delivery Point within the transmission path contracted by Customer as an alternate delivery point.

Rates

The Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will be specified in the Customer's Service Agreement.

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Annual Firm Transportation Off-System: Schedule G-AFTOFF (cont'd)

Reservation Charge

The reservation charge is the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the Customer's Service Agreement. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

PATH	RESERVATION RATE (PER DECATHERM PER MONTH)	
	MFV Rates	SFV Rates
Redwood to Off-System	$5.4087	$8.3095
Baja to Off-System	$5.8930	$9.0536
Silverado to Off-System	$5.4087	$8.3095
Mission to Off-System	$5.4087	$8.3095

Usage Charge

The Usage Charge is equal to the applicable usage rate for the Customer's contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

PATH	USAGE RATE (PER DECATHERM)	
	MFV RATES	SFV RATES
Redwood to Off-System	$0.1038	$0.0084
Baja to Off-System	$0.1129	$0.0089
Silverado to Off-System	$0.1038	$0.0084
Mission to Off-System	$0.1038	$0.0084

Additional Charges

The Customer is responsible for payment of any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-AFTOFF for further details.

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Seasonal Firm Transportation On-System Rates

Seasonal Firm Transportation On-System: Schedule G-SFT

Schedule G-SFT applies to the seasonal firm gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off- System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-SFT is available only for the transportation of natural gas within PG&E's service territory on the paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-SFT are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)

Any Delivery Point(s) to which gas is transported under this rate schedule must be an On- System Delivery Point.

Rates

The Customer has the option to elect either the Modified Fixed Variable (MFV) or the Straight Fixed Variable (SFV) rate structure, which will be specified in the Customer's Service Agreement.

Reservation Charge

The reservation charge is the applicable reservation rate multiplied by the Maximum Daily Quantity (MDQ) for the contracted path as specified in the Customer's Service Agreement. The Reservation Charge is payable each month regardless of the quantity of gas transported during the month.

PATH	RESERVATION RATE (PER DECATHERM PER MONTH)	
	MFV RATES	SFV RATES
Redwood to On-System	$6.4905	$9.9714
Baja to On-System	$7.0717	$10.8643
Baja to On-System (Core Procurement Groups only)	$6.3373	$8.6999
Silverado to On-System	$3.9215	$5.7667
Mission to On-System	$3.9215	$5.7667

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Seasonal Firm Transportation On-System: Schedule G-SFT (cont'd)

Usage Charge
The Usage Charge is equal to the applicable usage rate for the Customer's contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

PATH	USAGE RATE (PER DECATHERM)	
	MFV RATES	SFV RATES
Redwood to On-System	$0.1245	$0.0101
Baja to On-System	$0.1354	$0.0107
Baja to On-System (Core Procurement Groups only)	$0.0910	$0.0133
Silverado to On-System	$0.0665	$0.0058
Mission to On-System	$0.0665	$0.0058

Additional Charges
The Customer is responsible for payment of any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

For purposes of this rate schedule there are two (2) seasons per year, Winter and Summer. The Winter season extends for five (5) months, beginning November 1 and ending April 31. The Summer season extends for seven (7) months, beginning April 1 and ending October 31.

See Schedule G-SFT for further details.

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As-Available Transportation On-System Rates

As-Available Transportation On-System: Schedule G-AA

Schedule G-AA applies to As-available gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or a G-PARK or G-LEND account at the Citygate.
To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off-System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-AA is available only for the transportation of natural gas within PG&E's service territory on the paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AA are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point(s) to which gas is transported under this rate schedule must be an On-System Delivery Point.

Rates
The Customer shall pay a Usage Charge for each decatherm equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Usage Charge

PATH	USAGE RATE (PER DECATHERM)
Redwood to On-System	$0.3379
Baja to On-System	$0.3679
Silverado to On-System	$0.1954
Mission to On-System	$0.0000

Additional Charges
The Customer is responsible for payment of any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).
See Schedule G-AA for further details.

As-Available Transportation Off-System Rates

As-Available Transportation Off-System: Schedule G-AAOFF

Schedule G-AAOFF applies to As-available gas transportation service on PG&E's Backbone Transmission System to Off-System Delivery Point(s) only. Schedule G-AAOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-AAOFF are as follows:

PATH	RECEIPT POINT(S)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Freemont Peak, Essex, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point(s) to which gas is transported under this rate schedule must be an Off-System Delivery Point.

Rates
The Customer shall pay a Usage Charge for each decatherm equal to the applicable usage rate for the contracted path, multiplied by the quantity of gas delivered on the Customer's behalf.

Usage Charge

PATH	USAGE RATE (PER DECATHERM)
Redwood to Off-System	$0.3379
Baja to Off-System	$0.3679
Silverado to Off-System	$0.3379
Mission to Off-System	$0.3379
Mission to Off-System Storage Withdrawals	$0.0000

Additional Charges
The Customer is responsible for payment of any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Rates under this schedule are not negotiable. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule G-BAL (see Tariff Book).

See Schedule G-AAOFF for further details.

SB_GT&S_0354116

Negotiated Firm Transportation On-System Rates

Negotiated Firm Transportation On-System: Schedule G-NFT

Schedule G-NFT applies to the firm gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only, at negotiated rates. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or, a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following additional rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for further transportation and delivery of natural gas to an Off- System Delivery Point, one of the following additional rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-NFT is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NFT are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point(s) to which gas is transported under this rate schedule must be an On-System Delivery Point.

Rates
The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under Schedule G-NFT will be capped at 120 percent of the tariffed rate under Schedule G-AFT for a particular path, as follows: the negotiated rate (including all surcharges, costs and / or fees), converted to a volumetric-only rate at 100 percent load factor, shall be no greater than 120 percent of the Schedule G-AFT tariffed rate (including all surcharges, costs and / or fees), converted to a volumetric-only rate at 100 percent load factor under the Modified Fixed Variable (MFV) rate structure.

At PG&E's sole option, firm On-System capacity may be available under Schedule G-NFT at less than the rates under Schedule G-AFT. At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted.
The Customer is responsible for any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

SB_GT&S_0354117

Negotiated Firm Transportation Off-System: Schedule G-NFTOFF (cont'd)

To transport storage withdrawals On-System, Customers may convert all or part of a Firm On-System Redwood or Firm On-System Baja Exhibit to a Firm On-System Mission Exhibit at any time prior to 60 minutes before the close of the Timely Nomination Cycle, as set forth in Gas Rule 21. The negotiated transmission rate for this Mission Path service shall, unless otherwise agreed to, be zero. However, the full monthly demand charge is still applicable. Conversions of Firm On-System Baja Exhibits are limited to the amount of unsold Firm Redwood capacity available at the time of the requested conversion. Baja Exhibit conversions may be requested on a monthly basis, no more than five days prior to the end of the month, for a maximum term of one month. Redwood Exhibit conversions have no minimum term limit. See Rate Schedule G-NFT for further details.

Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule
G-BAL (see Tariff Book).

See Schedule G-NFT for further details.

SB_GT&S_0354118

Negotiated Firm Transportation Off-System Rates

Negotiated Firm Transportation Off-System: Schedule G-NFTOFF

Schedule G-NFTOFF applies to firm gas transportation service on PG&E's Backbone Transmission System to the Off-System Delivery Points at negotiated rates. Service under Schedule G-NFTOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below for off-system deliveries. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NFTOFF are as follows:

PATH	RECEIPT POINT(S)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Firm Off-System Delivery Points
Kern River Station to Southern California Gas Company
Fremont Peak to Kern River Gas Transmission

Backhaul Off-System Points
All off-system interconnection points are available as backhaul delivery points under this schedule if the upstream pipeline accepts backhaul nominations. Backhaul service is limited to the quantities of gas being delivered from the upstream pipeline.

Alternative Delivery Points
The Delivery Point to which gas is transported under this rate schedule shall be a Firm Off-System Delivery Point, unless the Customer elects both the Straight Fixed Variable (SFV) rate structure and the maximum allowable rate under G-NFTOFF. If the above conditions are met, the Customer may specify an On-System Delivery Point within the transmission path contracted by Customer as al alternative delivery point.

Rates
The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under Schedule G-NFTOFF will be capped at 120 percent of the Schedule G-AFTOFF tariffed rate for a particular path, as follows: the negotiated rate (including all surcharges, costs and / or fees), converted to a volumetric-only rate at 100 percent load factor, shall be no greater than 120 percent of the Schedule G-AFTOFF tariffed rate (including all surcharges, costs and / or fees), converted to a volumetric-only rate at 100 percent load factor under the Modified Fixed Variable (MFV) rate structure.

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Negotiated Firm Transportation Off-System: Schedule G-NFTOFF (cont'd)

At PG&E's sole option, firm Off-System capacity may be available on G-NFTOFF at less than the rates in Schedule G-AFTOFF. At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted.

The Customer is responsible for any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources. Transportation volumes will be subject to a shrinkage allowance in accordance with Rule 21 (see Tariff Book). Nominations are required for gas transported under this rate schedule (see Rule 21). Service under this schedule may be curtailed (see Rule 14 for details). Service shall be subject to all applicable terms, conditions and obligations of Schedule
G-BAL (see Tariff Book).

See Schedule G-NFTOFF for further details.

SB_GT&S_0354120

Negotiated As-Available Transportation On-System Rates

Negotiated As-Available Transportation On-System: Schedule G-NAA

Schedule G-NAA applies to As-available gas transportation service on PG&E's Backbone Transmission System to On-System Delivery Point(s) only, at negotiated rates. On-System Delivery Point(s) do not include an End-Use Customer's meter. On-System Delivery Point(s) may include: a delivery point pool; a PG&E storage account; a storage account with a third-party on-system storage facility; or, a G-PARK or G-LEND account at the Citygate.

To arrange for the further transportation and delivery of natural gas to an End-Use Customer's meter, one of the following rate schedules must be utilized: Schedules G-CT, G-NT, G-EG, G-NGV4, or G-WSL. To arrange for the further transportation and delivery of natural gas to an Off-System Delivery Point, one of the following rate schedules must be utilized: Schedules G-AFTOFF, G-AAOFF, G-NFTOFF or G-NAAOFF.

Service under Schedule G-NAA is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NAA are as follows:

PATH	RECEIPT POINT(S)
Redwood to On-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to On-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to On-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to On-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)

Any Delivery Point to which gas is transported under this rate schedule must be an On-System Delivery Point.

Rates

The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under Schedule G-NAA will be capped at 120 percent of the tariffed rate under Schedule G-AA for a particular path. At PG&E's sole option, As-available On-System capacity may be available under Schedule G-NAA at less than the rates under Schedule G-AA.

At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted. The Customer is responsible for any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

See Schedule G-NAA for further details.

SB_GT&S_0354121

Negotiated As-Available Transportation Off-System Rates

Negotiated As-Available Transportation Off-System: Schedule G-NAAOFF

Schedule G-NAAOFF applies to As-available gas transportation service on PG&E's Backbone Transmission System to Off-System Delivery Point(s), at negotiated rates. Schedule G-NAAOFF is available only for the transportation of natural gas within PG&E's service territory on the specific paths described below for off-system deliveries. PG&E will accept gas on Customer's behalf only at the Receipt Point(s) specifically designated in Customer's Gas Transmission Service Agreement.

Receipt Point(s) available for service on Schedule G-NAAOFF are as follows:

PATH	RECEIPT POINT(S)
Redwood to Off-System	Malin or other receipt point north of the Antioch Terminal not included in other backbone transmission paths
Baja to Off-System	Topock, Dagget, Kern River Station or other receipt points south of the Antioch Terminal not included in other backbone transmission paths
Silverado to Off-System	PG&E interconnections with California Production (see Gas Rule 1)
Mission to Off-System	PG&E's Market Center Citygate location, an On-System Delivery Point, PG&E's storage facilities or a third-party's storage facilities located in PG&E's service territory

Delivery Point(s)
Any Delivery Point to which gas is transported under this rate schedule must be an Off-System Delivery Point.

Rates
The term, take requirement, and rate are negotiable between PG&E and the Customer. Negotiated rates for transmission service shall not be less than PG&E's short-run marginal cost of providing the service. Negotiated transmission rates under G-NAAOFF will be capped at 120 percent of the tariffed rate under Schedule G-AAOFF for a particular path. At PG&E's sole option, as-available off-system capacity may be available hereunder at less than the rates under Schedule G-AAOFF.

At PG&E's sole option, negotiated offers satisfactory to PG&E may be accepted. The Customer is responsible for any applicable costs, taxes, and / or fees incurred by PG&E in taking delivery of third-party gas from intra- or interstate sources.

See Schedule G-NAAOFF for further details.

Exhibit D

Statement of Proposed Rate Changes

PACIFIC GAS AND ELECTRIC COMPANY

Implementation Plan Rate Impacts

Illustrative Class Average End-User Rates
($ per Therm)

	Rates Effective June 1, 2011 (1) (6)			
	Present June 2011 Rates	Gas Pipeline Safety Rate	Total Rate Including Gas Pipeline Safety Rate	Percent Change
CORE RETAIL - Bundled (2)				
Residential Non-CARE (4)	$1.223	$.052	$1.275	**4.3%**
Small Commercial Non-CARE (4)	$.975	$.052	$1.027	**5.3%**
Large Commercial	$.766	$.052	$.818	**6.8%**
NGV1 - (uncompressed service)	$.661	$.052	$.713	**7.9%**
NGV2 - (compressed service)	$1.912	$.052	$1.965	**2.7%**
CORE RETAIL - Transport Only (3)				
Residential Non-CARE (4)	$.650	$.052	$.702	**8.0%**
Small Commercial Non-CARE (4)	$.418	$.052	$.470	**12.5%**
Large Commercial	$.248	$.052	$.300	**21.0%**
NONCORE - Transportation Only (3)				
Industrial - Distribution	$.171	$.025	$.196	**14.6%**
Industrial - Transmission	$.069	$.025	$.094	**36.0%**
Industrial - Backbone	$.042	$.002	$.044	**5.0%**
Electric Generation - Transmission (G-EG-D/LT)	$.029	$.025	$.054	**86.0%**
Electric Generation - Backbone (G-EG-BB)	$.007	$.002	$.010	**28.6%**
NGV 4 - Distribution (uncompressed service)	$.155	$.025	$.180	**16.1%**
NGV 4 - Transmission (uncompressed service)	$.055	$.025	$.080	**45.2%**
WHOLESALE CORE AND NONCORE (G-WSL) (3)				
Alpine Natural Gas	$.026	$.025	$.051	**97.1%**
Coalinga	$.026	$.025	$.051	**96.8%**
Island Energy	$.027	$.025	$.052	**90.9%**
Palo Alto	$.025	$.025	$.050	**98.6%**
West Coast Gas - Castle	$.100	$.025	$.125	**24.9%**
West Coast Gas - Mather Distribution	$.123	$.025	$.148	**20.2%**
West Coast Gas - Mather Transmission	$.026	$.025	$.051	**96.0%**

ILLUSTRATIVE CLASS AVERAGE END-USER RATES
WITH PROXY NONCORE PROCUREMENT RATES (EQUAL TO CORE LARGE COMMERCIAL PROCUREMENT RATE)

($/th; Annual Class Averages)

	Present June 2011 Rates	Gas Pipeline Safety Rate	Total Rate Including Gas Pipeline Safety Rate	Percent Change
NONCORE - With Proxy Noncore Procurement Rate (5)				
Industrial - Distribution	$.689	$.025	$.714	**3.6%**
Industrial - Transmission	$.587	$.025	$.612	**4.2%**
Industrial - Backbone	$.560	$.002	$.562	**0.4%**
Electric Generation - Transmission (G-EG-D/LT)	$.547	$.025	$.572	**4.6%**
Electric Generation - Backbone (G-EG-BB)	$.525	$.002	$.527	**0.4%**
NGV 4 - Distribution (uncompressed service)	$.673	$.025	$.698	**3.7%**
NGV 4 - Transmission (uncompressed service)	$.573	$.025	$.598	**4.4%**
WHOLESALE CORE AND NONCORE (With Proxy Noncore Procurment Rate) (5)				
Alpine Natural Gas	$.544	$.025	$.569	**4.6%**
Coalinga	$.544	$.025	$.569	**4.6%**
Island Energy	$.545	$.025	$.570	**4.6%**
Palo Alto	$.543	$.025	$.568	**4.6%**
West Coast Gas - Castle	$.618	$.025	$.643	**4.0%**
West Coast Gas - Mather Distribution	$.641	$.025	$.666	**3.9%**
West Coast Gas - Mather Transmission	$.544	$.025	$.569	**4.6%**

Notes: See next page for notes

PACIFIC GAS AND ELECTRIC COMPANY
Notes Supporting Illustrative Class Average End User Rates

(1) June 1, 2011 rates are based on PG&E's 2011 General Rate Case (GRC) rate implementation filing (Advice Letters 3206-G & 3207-G), 2010 Biennial Cost Allocation Proceeding (BCAP) Decision D.10-06-035 and the Gas Accord V D.11-04-031.

(2) PG&E's bundled gas service is for core customers only. Intrastate backbone transmission costs are included in the end use rates paid by bundled core customers. Bundled service also includes a procurement cost for gas purchases, transportation on Canadian and Interstate pipelines, storage and core brokerage. An illustrative weighed average cost of gas (WACOG) of $0.429 per therm, adjusted for intrastate backbone usage charges, is assumed in all present and proposed bundled core rates. Core bundled rates also include the cost of transportation and delivery of gas from the city gate to the customer's burner tip, including local transmission, distribution, customer, public purpose and customer access charges.

(3) PG&E's end-use transportation-only gas service is for core and noncore customers. Transportation-only service begins at PG&E's city gate and includes the applicable costs of gas transportation and delivery on PG&E's local transmission (where applicable), distribution (where applicable), CPUC fees, customer access, public purpose program (where applicable) and customer class charges. Transportation-only customers must arrange for their own gas purchases and transportation to PG&E's city gate/local transmission system.

(4) California Alternate Rates for Energy (CARE) Customers receive a 20% discount off of the total bundled rate and are exempt from the CARE portion of PG&E's Public Purpose Program Surcharge (G-PPPS) rates.

(5) PG&E's proxy noncore procurement rate includes a procurement cost for gas purchases, transportation on Canadian and Interstate pipelines, backbone transmission, storage and core brokerage. An illustrative WACOG of $0.429 per therm, adjusted for intrastate backbone usage charges, is assumed in all present and proposed proxy noncore rates.

(6) Rates represent class averages. 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.

Exhibit E

Results of Operations at Proposed Rates

Pacific Gas and Electric Company

Statement of Proposed Changes and Results of Operation

Results of Operations at Proposed Rates

Pipeline Safety Enhancement Plan

(Implementation Plan)

(Thousands of Dollars)

Line No.	Description	2011 * Pipeline Safety Enhancement Plan	2012 Pipeline Safety Enhancement Plan	2013 Pipeline Safety Enhancement Plan	2014 Pipeline Safety Enhancement Plan	Line No.
		(A)	(B)	(C)	(D)	
	REVENUE:					
1	Revenue Collected in Rates	-	247,279	220,833	300,641	1
2	Plus Other Operating Revenue	-	-	-	-	2
3	Total Operating Revenue	-	247,279	220,833	300,641	3
	OPERATING EXPENSES:					
4	Energy Costs	-	-	-	-	4
5	Gathering (in Transmission)	-	-	-	-	5
6	Storage	-	968	-	877	6
7	Transmission	-	230,102	154,839	143,077	7
8	Distribution	-	-	-	-	8
9	Customer Accounts	-	-	-	-	9
10	Uncollectibles	-	768	686	933	10
11	Customer Services	-	-	-	-	11
12	Administrative and General	-	-	-	-	12
13	Franchise Requirements	-	2,406	2,148	2,925	13
14	Amortization	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	16
17	Other Adjustments	-	-	-	-	17
18	Subtotal Expenses:	-	234,244	157,673	147,812	18
	TAXES:					
19	Superfund	-	-	-	-	19
20	Property	-	171	2,164	6,776	20
21	Payroll	-	-	-	-	21
22	Business	-	-	-	-	22
23	Other	-	-	-	-	23
24	State Corporation Franchise	-	(1,964)	(3,153)	(1,790)	24
25	Federal Income	-	(3,569)	999	18,634	25
26	Total Taxes	-	(5,362)	10	23,620	26
27	Depreciation	-	6,197	21,026	42,606	27
28	Fossil Decommissioning	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	29
30	Total Operating Expenses	-	235,079	178,709	214,038	30
31	Net for Return	-	12,200	42,124	86,603	31
32	Rate Base	-	138,791	479,221	985,239	32
	RATE OF RETURN:					
33	On Rate Base	**8.79%**	**8.79%**	**8.79%**	**8.79%**	33
34	On Equity	**11.35%**	**11.35%**	**11.35%**	**11.35%**	34

* 2011 Revenue Requirement of $224 million excluded from cost recovery

Exhibit F

List of cities and counties to which Notice will be sent

SERVICE OF NOTICE OF APPLICATION

In accordance with Rule 3.2(b), Applicant will mail a notice to the following, stating in general terms its proposed change in rates.

State of California

To the Attorney General and the Department of General Services.

State of California
Office of Attorney General
1300 I St Ste 1101
Sacramento, CA 95814

and

Department of General Services
Office of Buildings & Grounds
505 Van Ness Avenue, Room 2012
San Francisco, CA 94102

Counties

To the County Counsel or District Attorney and the County Clerk in the following counties:

Alameda
Alpine
Amador
Butte
Calaveras
Colusa
Contra Costa
El Dorado
Fresno
Glenn
Humboldt
Kern
Kings
Lake
Lassen
Madera
Marin
Mariposa
Mendocino
Merced
Modoc
Monterey
Napa
Nevada
Placer
Plumas
Sacramento
San Benito
San Bernardino
San Francisco
San Joaquin
San Luis Obispo
San Mateo
Santa Barbara
Santa Clara
Santa Cruz
Shasta
Sierra
Siskiyou
Solano
Sonoma
Stanislaus
Sutter
Tehama
Trinity
Tulare
Tuolumne
Yolo
Yuba

Municipal Corporations

To the City Attorney and the City Clerk of the following municipal corporations:

Alameda
Albany
Amador City
American Canyon
Anderson
Angels
Antioch
Arcata
Arroyo Grande
Arvin
Atascadero
Atherton
Atwater
Auburn
Avenal
Bakersfield
Barstow
Belmont
Belvedere
Benicia
Berkeley
Biggs
Blue Lake
Brentwood
Brisbane
Buellton
Burlingame
Calistoga
Campbell
Capitola
Carmel
Ceres
Chico
Chowchilla
Citrus Heights
Clayton
Clearlake
Cloverdale
Clovis
Coalinga
Colfax
Colma
Colusa
Concord
Corcoran
Corning
Corte Madera
Cotati
Cupertino
Daly City
Danville
Davis
Del Rey Oakes
Dinuba
Dixon
Dos Palos
Dublin
East Palo Alto
El Cerrito
Elk Grove
Emeryville
Escalon
Eureka
Fairfax
Fairfield
Ferndale
Firebaugh
Folsom
Fort Bragg
Fortuna
Foster City
Fowler
Fremont
Fresno
Galt
Gilroy
Gonzales
Grass Valley
Greenfield
Gridley
Grover Beach
Guadalupe
Gustine
Half Moon Bay
Hanford
Hayward
Healdsburg
Hercules
Hillsborough
Hollister
Hughson
Huron
Ione
Isleton
Jackson
Kerman
King City
Kingsburg
Lafayette
Lakeport
Larkspur
Lathrop
Lemoore
Lincoln
Live Oak
Livermore
Livingston
Lodi
Lompoc
Loomis
Los Altos
Los Altos Hills
Los Banos
Los Gatos
Madera
Manteca
Maricopa
Marina
Martinez
Marysville
McFarland
Mendota
Menlo Park
Merced
Mill Valley
Millbrae
Milpitas
Modesto
Monte Sereno

Monterey
Moraga
Morgan Hill
Morro Bay
Mountain View
Napa
Newark
Nevada City
Newman
Novato
Oakdale
Oakland
Oakley
Orange Cove
Orinda
Orland
Oroville
Pacific Grove
Pacifica
Palo Alto
Paradise
Parlier
Paso Robles
Patterson
Petaluma
Piedmont
Pinole
Pismo Beach
Pittsburg
Placerville
Pleasant Hill
Pleasanton
Plymouth
Point Arena
Portola
Portola Valley
Rancho Cordova
Red Bluff
Redding
Redwood City
Reedley
Richmond
Ridgecrest
Rio Dell
Rio Vista
Ripon
Riverbank
Rocklin
Rohnert Park
Roseville
Ross
Sacramento
Saint Helena
Salinas
San Anselmo
San Bruno
San Carlos
San Francisco
San Joaquin
San Jose
San Juan Bautista
San Leandro
San Luis Obispo
San Mateo
San Pablo
San Rafael
San Ramon
Sand City
Sanger
Santa Clara
Santa Cruz
Santa Maria
Santa Rosa
Saratoga
Sausalito
Scotts Valley
Seaside
Sebastopol
Selma
Shafter
Shasta Lake
Soledad
Solvang
Sonoma
Sonora
South San Francisco
Stockton
Suisun City
Sunnyvale
Sutter Creek
Taft
Tehama
Tiburon
Tracy
Trinidad
Turlock
Ukiah
Union City
Vacaville
Vallejo
Victorville
Walnut Creek
Wasco
Waterford
Watsonville
West Sacramento
Wheatland
Williams
Willits
Willows
Windsor
Winters
Woodland
Woodside
Yountville
Yuba City