PACIFIC GAS AND ELECTRIC COMPANY

GAS TRANSMISSION AND DISTRIBUTION
GAS ENGINEERING
GAS INTEGRITY MANAGEMENT AND TECHNICAL SUPPORT
Risk Management

PG&E

Procedure for Risk Management

Procedure No. RMP-02
Rev. 5
External Corrosion Threat Algorithm

Prepared By: [redacted] Date: 11/21/01

Approved By: [redacted] Lead Risk Management Engineer Date: 11/21/01

Approved By: [redacted] Manager, System Integrity Date: 11/26/01

Rev. No.	Date	Description	Prepared By	Approved By	Approved Manager, System Integrity
0	11/26/01	Initial Issue	[redacted]	[redacted]	[redacted]
1	1/8/03	Revised as Shown			
2	6/13/05	Revised as shown-added section 5.0			
3	10/22/05	Revised as shown			
4	7/12/06	Revised as shown			
5	1/14/10	Revised as shown			[redacted]

Table of Contents

1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the External Corrosion Threat Algorithm for the determination of Likelihood of Failure and Risk for PG&E's Risk Management Program (RMP) and Integrity Management Program.

2.0 SCOPE

2.1 Transmission

This guideline is applicable to all of PG&E's gas transmission pipeline facilities and is to be used in conjunction with RMP Procedure 01. The algorithm provided in this procedure is for Pipelines. It is not applicable to regulator, compressor, or storage station facilities

The Integrity Management Group is responsible for managing risk within the scope of this procedure. The Integrity Management Group shall establish and manage the risk of each pipeline facility by utilizing industry and regulatory accepted methodologies appropriate for PG&E's gas transmission facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure in relation to determining the external corrosion likelihood of failure.

2.2 Distribution

Gas Distribution System Integrity risk ranking is intended to meet the requirements of subpart P of 49 CFR 192. Currently it uses a Subject Matter Expert approach to identify 5
and prioritize risks. That process is detailed in Section 6.2 of this document.

3.0 INTRODUCTION

The risk management process is a process of calculating risk, developing risk mitigation plans to bring and maintain risk within an acceptable risk profile, and monitoring risk to accommodate changes in the factors which affect risk. The Integrity Management Program (IMP) is a program established by PG&E to address the integrity management rules in 49 CFR Part 192 Subpart O. Procedure RMP-01 provides a procedure for the Risk Management Process. Procedure RMP-06 provides procedures for compliance with the Integrity Management Program. This procedure supports the calculation of risk, required by Procedure RMP-01 and RMP-06, due to one of the basic threats imposed on gas pipelines, External Corrosion (EC).

As described in RMP-01, Risk is defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). A relative risk calculation methodology is used to establish risk for all pipeline segments within the scope of RMP-01. The method used to calculate risk is based on an index model and qualitative scoring approach. Likelihood

Of Failure (LOF) is defined as the sum of the following threat categories: External Corrosion (EC), Third Party (TP), Ground Movement (GM) and Design/Materials (DM).

Each threat category is weighted in proportion to PG&E and industry failure experience. EC is weighted at 25%. The weightings on the threat categories will be reviewed and approved annually by the Consequence Steering Committee. For each threat category, the appropriate steering committee will identify the significant factors that influence the threat's likelihood of failure. For each factor, a percentage weighting will be established to identify the factor's relative significance in determining the threat's likelihood of failure within the threat algorithm. Points will be established based on criteria that the committee feels is significant to determining the threat's likelihood of failure due to each factor and the relative severity of failure (leak-before-break vs. rupture). (Negative points may be assigned where current assessments have been made to confirm pipeline integrity and/or mitigation efforts have eliminated or lowered susceptible to a threat.) Generally, the summation of the percentage weightings for all of the factors within each threat will be 100%. (There may be exceptions to permit the consideration of very unusual conditions.)

For the threat of EC, the scoring is based on direction from the EC Steering Committee. The EC Steering Committee shall meet once each calendar year and shall review this procedure per the requirements of RMP-01.

The Distribution Integrity Management Program (DIMP) is a program established by PG&E to address the integrity management rules in 49 CFR Part 192 Subpart P. Procedure RMP-15 provides details for compliance with the Integrity Management Program. This procedure supports the calculation of risk due to one of the basic threats imposed on gas pipelines, External Corrosion (EC). 5

The EC threat for distribution piping is addressed in section 6.2 of this document. Currently this algorithm determines the highest risk items so they can be prioritized as a group.

4.0 Roles and Responsibility

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager, System Integrity	• Supervise completion of work (schedule/quality) • Monitor compliance to procedure – take corrective actions as necessary. • Assign qualified individuals • Ensure Training of assigned individuals • Assign Steering Committee Chairman, and ensure that meetings are held once each calendar year.
Steering Committee Chairman (Risk Management Engineers)	Integrity Management Program Manager (except for TP Steering Committee – chairman reports to Manager System Integrity)	• Arrange meetings. • Review procedure with committee per RMP-01 • Provides meeting minutes • Ensures action items are completed.
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman. • Provide review and direction to procedure.
Risk Management Engineers	Integrity Management Program Manager	• Perform calculations per procedure.

5.0 Training and Qualifications

See RMP-06 for qualification requirements. Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training:	How Often
Integrity Management Program Manager	Procedure review of RMP-01 and RMP-02	• Upon initial assignment • Once each calendar year.
Steering Committee Chairman	Procedure review of RMP-01 and RMP-02	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.
Steering Committee Members (Subject Matter Experts)	Review RMP-02 and Steering Committee requirements of RMP-01	• Once each calendar year at the time of the steering committee meeting.
Risk Management Engineers	Review Procedure RMP-02	• Upon initial assignment • Once each calendar year. • As changes are made to the procedure.

5

6.0 EC Threat Algorithm

6.1 Gas Transmission

Scoring for the External Corrosion (EC) threat algorithm shall be calculated per the direction of the EC Steering Committee. The committee has determined that the factors in A through M of this section are significant for determining the Likelihood of Failure (LOF) of a gas pipeline due to EC. The EC contribution to LOF shall be the summation of assigned points times the assigned weighting of the following factors:

A) Soil Resistivity (4% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
Less than or equal 500 Ohm-Centimeters	100	4
501 to 1000 Ohm-Centimeters	80	3.2
1001 to 2000 Ohm-Centimeters	60	2.4
2001 to 4000 Ohm-Centimeters	40	1.6
4001 to 10,000 Ohm-Centimeters	20	0.8
Above 10,000 Ohm-Centimeters	10	0.4

Default = Above 10,000 Ohm-Centimeters

B) Corrosion Survey Criteria (5% Weighting): Points will be awarded as follows:

Criteria	Points	Contrib.
No CIS*/ readings	50	2.5
CIS & meets criteria for acceptance	-100	-5
CIS & does not meet acceptance criteria	300	15

* CIS – (Close Interval Survey) This information is provided to the RMP by the Corrosion Engineer and, if acceptable, is considered valid for ten years. If the CIS does not meet acceptance criteria, it is valid until repeated.

C) Coating Visual Inspection[1] (8% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Severely disbonded, (Poor)	100	8
Locally damaged, disbonded (Fair)	50	4
Superficial damage only (Good)	20	1.6
Intact and bonded (Excellent)	10	0.8
Bare Pipe or No Inspection (Coating Age[2] ≤ 5 Years)	11	0.88
Bare Pipe or No Inspection (Coating Age[2] > 5 to ≤ 20 Years)	19	1.52
Bare Pipe or No Inspection (Coating Age[2] > 20 to ≤ 30 Years)	29	2.32
Bare Pipe or No Inspection (Coating Age[2] > 30 Years)	51	40.8

[1] Inspection data greater than 20 years old shall not be used unless the information reflects a condition that is fair or poor. In such cases, points will be awarded per the inspection regardless as to when the inspection was performed.

[2] For Bare Pipe substitute Pipe Age.

D) Casing Survey (3% Weighting): Points awarded as follows:

Criteria	Points	Contrib.	
No casing or Gelled	0	0	
Existing casing	20	0.6	5
Metallic shorted casing	100	3	

E) In-Line-Inspection (ILI) (5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
No survey performed	0	0
Inspection > 10 years old	-100	-5
Inspection 5 to 10 years old	-300	-15
Inspection 2 to <5 years old	-600	-30
Inspection <2 years old	-600	-30

F) External Corrosion Leak[1] Rate (14% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Leak in last 5 years	100	14
Leak in last 10 Years	80	11.2
Leak age >10 years	50	7
No reported Leaks	0	0

[1] Points applied to all pipe segments of similar vintage and coating type within a 1 mile radius of a leak.

G) Coating Design (8% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Shielding Coatings	100	8
Non-Shielding Coatings	10	0.8
Bare	30	2.4
Paint	10	0.8
Default (Installation date ≥ 1960 – Assume Tape or equiv.)	100	8
Default (Installation date ≤ 1960 – Assume HAA or equiv.)	10	0.8

5

H) DC/AC Interference (10% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
High or medium voltage within 500' of a Gas Pipeline without Cathodic Protection	100	9
High or medium voltage w/i 500' w/CP	50	4.5
No high or medium voltage	0	0

I) Coating Age (5% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
>30 years	100	5
>20 to 30 years	80	4
>10 to 20 years or uncoated	30	1.5
10 years or less	10	0.5

J) MOP vs. Pipe Strength* (8% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
>60%	100	8
50% to 60%	80	6.4
40% to <50%	50	4
30% to <40%)	30	2.4
20% to <30%	10	0.8
Less than 20%	5	0.4

* Pipe Strength shall be determined to be equal to (SMYS)(2)(t)(Jef)/(OD).

K) Pipe Visual Inspection[1] (10% Weighting): Points awarded as follows:

Criteria	Points	Contrib.
Heavy pitting or gouging (Poor)	100	10
Light pitting or gouging (Fair)	50	5
Heavy rusting	20	2
Light rusting (Good)	10	1
No pitting or rusting (Excellent)	0	0
No Inspection (Pipe Age ≤ 5 Years)	0	0
No Inspection (Pipe Age > 5 to ≤ 20 Years)	10	1
No Inspection (Pipe Age > 20 to ≤ 30 Years)	20	2
No Inspection (Pipe Age > 30 Years)	40	4

[1] Inspection data greater than 20 years old shall not be used unless the information reflects a condition that is fair or poor.

In such cases, points will be awarded per the inspection regardless as to when the inspection was performed.

L) Test Pressure (TP)(5% Weighting): Points awarded as follows: 5

Criteria	Points	Contrib.
No Records Available	0	0
TP age is ≤ ASME B31.8S Table 3 requirements for Hydrostatic Test Interval	-200	-10
TP age is ≤ 3 years more than ASME B31.8S Table 3 requirements for Hydrostatic Test Interval	-100	-5
TP is > 3 years more than ASME B31.8S Table 3 requirements for Hydrostatic Test Interval	0	0

M) External Corrosion Direct Assessment (ECDA) (Weighting 10%) Points awarded as follows:

Criteria	Points	Contrib.
ECDA Completed*	-200	-20
ECDA Not Completed	0	0

* ECDA must have been completed within the last ten years.

6.2 Gas Distribution

PG&E's Distribution Integrity Management Plan (DIMP) (RMP-15) addresses each of the GPTC Appendix G-192-8 guide's seven major components. These components are as follows:

A. Knowledge of the distribution system – design, maintenance and operation
B. Threat Identification process
C. Risk evaluation and ranking of threats
D. Implement measures to manage risks
E. Measure and monitor results
F. Periodic evaluation of program for improvements
G. Reports to government agencies

External Corrosion (EC) threat algorithms for Gas Distribution are developed following the guidelines in RMP-15 and they are described as follows:

A) Knowledge of the system – PG&E's records and data bases that define the distribution system and what type of information they provide are described in Table 1.3 of RMP-15.

B) How Threats are identified – The EC threats to the distribution system are identified by Subject Matter Experts (SME). The pool used to select the members will include Corrosion Engineers at PG&E, a Gas Distribution Engineer at PG&E, and a Pipeline Engineer at PG&E.

C) Risk Evaluation and ranking of threats – Identification is performed by the SME team who then rank the Likelihood and Consequence of each threat with H, M or L. A value is then assigned to each of the ranks such as: H = 3, M = 2 and L = 1. The value of the Likelihood (L) X Consequence (C) of each SME's judgment will be calculated and then the average of all SMEs' risk values will be calculated as the relative risk value, R.

The relative risk values of the threat, R = 1/n (∑ (Li X Ci)) (i = 1 to n)

n: Total number of SMEs.

In the table below, the consequence of the threat is that it will not be able to safely and reliably perform it's intended function.

Summary Table of Relative Risk Value (R) Per SMEs ballot results

Subcategory 1	Subcategory 2	Threat	Ave Risk Rank	NOTES
External Corrosion - Coated Steel	Coated pipe not under Cathodic Protection	Pipe with any coating type not under Cathodic protection.	6.25	
External Corrosion - Coated Steel	Shielding	The use of some materials for pipe wrap coatings will shield CP current when disbonded from pipe. Mainly tape products - Polycon.	4.5	
External Corrosion - Coated Steel	Anode Life in Impressed current systems	Anode failure in impressed current systems may cause the system to be under protected while funding is sought for anode replacement. Corrosion leaks may develop.	4.5	
External Corrosion - Coated Steel	Unsure of areas not protected	Cathodic protection areas and steel within the areas are not well defined creating uncertainty in if all steel is under protection.	4	
External Corrosion - Cast Iron		Cast Iron - Oxidation of iron leaving graphite matrix. Additional threats include earth movement and Joint leaks. Normally not under CP.	4	
External Corrosion - Coated Steel	CPA impressed current systems below 850mv	There are many operational situations that cause areas to be without protection for short intervals of time. The accumulative effect will cause corrosion leaks to develop.	3.25	

Subcategory 1	Subcategory 2	Threat	Ave Risk Rank	NOTES
External Corrosion - Bare steel	Not Under Cathodic Protection	No Cathodic Protection, Corrosion leaks develop. No rupture threat.	3.25	
External Corrosion - Coated Steel	Stray Currents	CPA protection adversely affected by stray electrical currents from third party sources.	2.75	
External Corrosion - Coated Steel	Unprotected steel services in GPRP.	Steel services tied into plastic main without Cathodic protection.	2.75	
External Corrosion - Coated Steel	Use of locating wire to carry CP current	Galvanic protection is inadequate to protect wire. Wire corrodes to an open circuit. Isolated steel looses protection and develops leaks.	2.25	
External Corrosion - Coated Steel	Non-corroable services (the riser portion)	Non- Corroable services have a plastic service line within a steel riser tube. The riser tube is unprotected and fails in corrosion. The plastic service line is then vulnerable to mechanical damage.	2.25	
Copper Services	Internal Corrosion	Internal Corrosion resulting in a pin hole leak. Close proximity to building allows for migration under the building.	2.25	
Copper Services	External Corrosion on adjacent Steel	Copper and Steel form a galvanic cell where steel is more anodic. Steel corrodes allowing leakage.	2.25	
External Corrosion - Coated Steel	Not Under Cathodic Protection	Coated steel pipe not under cathodic protection will corrode at holidays in coating.	2.25	
External Corrosion - Coated Steel	GPRP pipe installed without Cathodic Protection.	Pipe replaced without Cathodic protection added.	2	
External Corrosion - Wrought Iron	Under Cathodic Protection	Wrought Iron - Cathodic Protection is in adequate. Corrosion leaks develop. No rupture threat. Location of wrought iron in the system is uncertain due to problems with material specifications. Notations of Iron may be cast or wrought. Treated the same as steel in GPRP. May be bare or not.	2	
External Corrosion - Wrought Iron	Not Under Cathodic Protection	Wrought Iron - No Cathodic Protection. Corrosion leaks develop. No rupture threat. Location of wrought iron in the system is uncertain due to problems with material specifications. Notations of Iron may be cast or wrought. Treated the same as steel in GPRP. May be bare or not.	2	

Subcategory 1	Subcategory 2	Threat	Ave Risk Rank	NOTES
External Corrosion - Coated Steel	CPA Resurvey issues	Bi-monthly pipe to soil reads may not be read in the best place to determine CPA protection.	2	
External Corrosion - Coated Steel	Casings	NTSB incident report identifies atmospheric corrosion within casings as a threat to integrity.	1.5	
Copper Services	Circumferen tial corrosion	Circumference corrosion resulting in a high volume leak migrating to a building.	1.5	
External Corrosion - Coated Steel	Use of locating wire to carry CP current	Locating wire is too small in diameter to carry CP current resulting in inadequate protection of isolated steel. Steel develops leaks.	1.25	
External Corrosion - Bare steel	Under Cathodic Protection	CP current is in adequate. Corrosion leaks develop. No rupture threat.	1	
Internal Corrosion	Non-copper	Water inside steel distribution pipes permits internal corrosion. Repair of pipe with general internal corrosion is very expensive.	1	

D) Implement Measure to Manage Risk – These risk rankings will be used to identify and implement measures to manage the risk.