**Docket No. SA-534**

**Exhibit No. 2-AV**

# NATIONAL TRANSPORTATION SAFETY BOARD

**Washington, D.C.**

EXCERPTS FROM THE
PG&E RISK MGMT PLAN
RMP-01, RMP-02, RMP-03
RMP-04, RMP-05, AND RMP-08

(52 Pages)

# PACIFIC GAS AND ELECTRIC COMPANY

CALIFORNIA GAS TRANSMISSION
GAS SYSTEM MAINTENANCE & TECHNICAL SUPPORT
SYSTEM INTEGRITY SECTION
Risk Management

## Procedure for Risk Management

Procedure No. RMP-01
Rev. 0
Risk Management

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## *Table of Contents*


| | | |
|---|---|---|
| **1.0** | **PURPOSE** | **3** |
| **2.0** | **SCOPE** | **3** |
| **3.0** | **INTRODUCTION** | **3** |
| **4.0** | **Roles and Responsibility** | **5** |
| **5.0** | **Training and Qualifications** | **6** |
| **6.0** | **RISK DETERMINATION** | **6** |
| | 6.1 RISK DEFINITION | 6 |
| | 6.2 CALCULATION METHODOLOGY | 7 |
| | 6.3 LIKELIHOOD OF FAILURE (LOF) | 8 |
| | 6.4 CONSEQUENCE OF FAILURE (COF) | 9 |
| | 6.4.1 IMPACT ON POPULATION (IOP) | 10 |
| | 6.4.2 IMPACT ON ENVIRONMENT (IOE) | 11 |
| | 6.4.3 IMPACT ON RELIABILITY (IOR) | 12 |
| **7.0** | **RISK MITIGATION** | **13** |
| | 7.1 REVIEW AND ESTABLISHMENT OF TARGET RISK THRESHOLDS | 13 |
| | 7.2 INSPECTIONS | 14 |
| | 7.3 PROJECT PLANNING | 14 |
| | 7.4 REHABILITATION | 15 |
| | 7.5 PUBLIC SAFETY INFORMATION PR0GRAM (PSIP) | 15 |
| **8.0** | **RMP MAINTENANCE** | **16** |
| | 8.1 FACILITY UPDATE | 16 |
| | 8.2 HAZARD UPDATE | 16 |
| | 8.3 CONSEQUENCE UPDATE | 16 |
| | 8.4 ALGORITHM REVIEW | 17 |
| | 8.5 REVISION TO RISK CALCULATIONS | 17 |
| **7.0** | **RISK FOR INTEGRITY MANAGEMENT** | **17** |

# 1.0 PURPOSE

The purpose of this procedure is to provide a process for maintaining California Gas Transmission's (CGT) Risk Management Program (RMP) and complying with the requirements for risk calculations as part CGT's Integrity Management Program (RMP-06).

# 2.0 SCOPE

This procedure is applicable to all of CGT's gas transmission pipeline facilities, including line pipe and regulating station facilities. At this time, this procedure is not applicable to the following:

- Compressor Station Facilities (other than piping);
- Storage Facilities (other than piping);
- Gas Gathering 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 CGT facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure.

Risk information shall be communicated to management and other appropriate CGT personnel for project planning, risk mitigation, inspection planning, and regulatory reporting. Per RMP-06, risk for each pipeline segment shall be calculated annually.

**The procedure applies to both covered and non-covered pipe segments as defined in RMP-08. In addition to the requirements specified in this procedure, RMP activities associated with covered pipeline segments must also comply with the requirements of RMP-06.**

# 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 that affect risk. PG&E applies this process to all pipelines system-wide and annually considers assessments or mitigation needed to ensure the on-going integrity of all pipelines.

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-06 provides an overall description and process for CGT's Integrity Management Program. Since RMP-01 supports the calculation of risk associated with pipelines covered by the IMP, it is referenced by RMP-06.

RMP-01 is referenced to calculate the overall risk; the combination of the likelihood of failure due to five of the basic pipeline threats (external corrosion, third party, ground movement, and design/materials) and the consequence of failure. Other threats, such as Internal Corrosion (IC) and Stress Corrosion Cracking (SCC), may be added to the procedure in the future if they become more relevant to our pipeline system. IC and SCC likelihoods have not been included at this time because they are only applicable to 12.26 and 4.33 miles of HCA pipe, respectively. Rather than dilute the risk calculation for the remaining 98% of the pipeline system, pipelines with these threats were prioritized as "high risk" and the likelihood factors were not included in the overall risk calculation. See § 9.0 for additional details. 5

An inventory of all the pipeline design attributes, operating conditions, environment (e.g., structures, faults, etc.), threats to the structural integrity, leak experience, and inspection findings must be developed and maintained. Risk must be calculated based on an immense inventory of assembled attributes. The risk values need to be reviewed and criteria for acceptance established, risk mitigation plans developed, budgeted and completed, and conditions monitored to update criteria, risk values, and mitigation plans, as necessary, to accommodate new information. (New information could include new damage prediction models, changes to population in proximity to a pipeline, changes to system operating characteristics which could effect safety margin, damage accumulation, the number of customers out of service, or gas load, new seismic or environmental hazard identification, inspection findings as they relate to the physical condition of the pipe or the systems needed to protect the pipeline or component from damage or degradation, or changes in the potential for third party damage.)

Because threats to the pipeline and consequences of a failure change with time, the process of monitoring and adjusting risk mitigation plans is an ongoing process. The risk management process is a methodology utilizing pipeline characteristics (physical and environmental), qualitative risk assessment, quantitative risk analysis, and decision-risk analysis methods to determine a cost-effective risk management of CGT's pipeline facilities. The process follows these basic steps: 5

- Accumulate facility design attributes, existing condition, potential threats, and failure consequence,
- Determine Likelihood of Failure (LOF) for each pipeline segment,
- Determine Consequence of Failure (COF) for each pipeline segment,
- Calculate risk for each pipeline segment based on the Likelihood of Failure and the Consequence of Failure,
- Develop a system wide risk mitigation strategy,
- Propose and prioritize rehabilitation projects or inspections based on the damage mechanism, threat, and risk, and finally,
- Monitor and adjust the process, as necessary, to incorporate changes in technology, changes in information, or changes in code or regulatory requirements.

## 4.0 Roles and Responsibility

Specific responsibilities for ensuring compliance with this procedure are as follows: 5

| Title | Reports to: | Responsibilities |
|---|---|---|

| Title | Reports to: | Responsibilities |
|---|---|---|
| Manager, System Integrity | Director, Gas System Maintenance & Technical Support | • Review and approve procedure<br>• Concur on selection of Steering Committee Chairperson and membership |
| Integrity Management Program Manager | Manager, System Integrity | • Supervise completion of work (schedule/quality)<br>• Monitor compliance to procedure – take corrective actions as necessary.<br>• Assign qualified individuals<br>• Ensure Training of assigned individuals<br>• Assign Steering Committee Chairperson and members, and ensure that meetings are held once each calendar year. |
| Steering Committee Chairperson (Risk Management Engineers) | Integrity Management Program Manager (except for TP Steering Committee – chairperson reports to Manager System Integrity) | •Arrange meetings.<br>•Review procedure with committee per RMP-01<br>•Provides meeting minutes<br>•Ensures action items are completed. |
| Steering Committee Members (Subject Matter Experts) | Various | •Attend meetings as requested by Steering Committee Chairman.<br>•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: 5

| Position | Type of Training: | How Often |
|---|---|---|
| Integrity Management Program Manager | Procedure review of RMP-01 | • Upon initial assignment<br>• Once each calendar year. |
| Steering Committee Chairperson | Procedure review of RMP-01 | • Upon initial assignment<br>• Once each calendar year.<br>• As changes are made to the procedure. |
| Steering Committee Members (Subject Matter Experts) | Steering Committee requirements of RMP-01. | • Once each calendar year at the time of the steering committee meeting. |
| Risk Management Engineers | Procedure Review of RMP-01 and RMP-06. | • Upon initial assignment<br>• Once each calendar year.<br>• As changes are made to the procedure. |

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## 6.0 RISK DETERMINATION

6.1 ***RISK*** shall be defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF).

**[RISK = LOF X COF]** *(Equation 1)*

In general, the source of information used to calculate risk shall be obtained from PG&E's Geographical Information System (GIS). Exceptions are noted within RMP procedures. There are also special cases where updated information is made available from other sources (such as from Pipeline Engineers, In-Line-Inspection (ILI) reports, Corrosion Engineers, or District Personnel.).

6.2 ***CALCULATION METHODOLOGY:*** A relative risk calculation methodology shall be used to establish risk. Risk will be calculated per this procedure for all pipeline segments within the scope of this procedure. A pipeline segment shall be defined as the length of contiguous pipeline with the same piping specification, class location, and Integrity Management HCA designation. (Pipe segments are as shown in GIS.) The method used to calculate risk shall be based on an index model and qualitative scoring approach. The scoring shall be based on expert direction from appropriately staffed Steering Committees. For each major component of the integrity management program, a Steering Committee shall be established to provide technical review and input to the program. There are currently five committees covering External Corrosion, Third Party damage, Ground Movement, Design/Materials, and Consequence. Requirements for the Steering Committees are as follows:

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6.2.1 The Steering Committees shall be comprised of a minimum of five individuals with expertise in the particular subject matter. It is the responsibility of the Integrity Management Program Manager, with the concurrence of the Manager of System Integrity, to select a range of individuals with knowledge and experience on the subject matter for which they are contributing. A list of the current membership shall be documented and included in RMP File 7.1.

6.2.2 For each steering committee, the Integrity Management Program Manager, with the concurrence of the Manager of System Integrity, shall assign a Committee Chairperson. The Chairperson is responsible for scheduling meetings, conducting the meeting in accordance with the requirements of this procedure, preparing meeting minutes, preparing necessary supporting material (risk ranked pipelines and applicable GIS themes) prior to the meeting, and making necessary changes to procedures following the meeting.

6.2.3 The committees shall meet at least once each calendar year to review and approve the methodology used to calculate risk and determine if changes are advisable.

6.2.4 At each meeting or at least each calendar year, the committee shall review the overall process of risk calculations provided by this procedure, the detailed requirements for conducting the meeting as contained in this section of RMP-01 (because the Consequence Steering Committee is responsible for this procedure, the committee will perform a detailed review.), and a detailed review of the requirements of the procedure for which they are providing direction. 5

6.2.5 At each meeting or at least each calendar year, the committee shall review, at a minimum, the ten most highly ranked segments for the threat or consequence for which the committee provides guidance. For the committees that address one of the threats, the review shall at a minimum consider the following:

- The ten pipeline segments with the highest LOFs for the threat,
- The ten pipeline segments with the highest LOF X COF of the threat,
- Ten additional pipeline segments with risk values spread through the range of values
- Performance metrics (such as the number of leaks and applicable characteristics) relevant to procedure. (See RMP-06 Section 10)

For the Consequence Steering Committee, the review shall at a minimum consider:

- The ten pipeline segments with the highest COF,
- The ten pipeline segments with the highest IMA COF,
- The ten pipeline segments with the highest Total Risk,
- Ten additional pipeline segments with risk values spread through the range of values
- Performance metrics (such as incidences and applicable characteristics) relevant to the consequence of a failure.

In reviewing each of these segments, the committee shall determine if, in the opinion of the committee, the ranking is appropriate or changes in the risk calculation algorithms is required. Consideration shall be made to the relative ranking of the various components used to calculate risk and the need for inclusion of other important information that may not have been included. The review should also consist of integrating all of the relevant (based on the procedure being evaluated) layers and themes in GIS and reviewing the integrated data (not just aggregating the information in a spreadsheet) in determining the validity of the risk algorithms.

Each steering committee will identify the significant attributes that influence the threat's LOF or COF, as appropriate. For each attribute, a percentage weighting will be established or reviewed to identify the factors' relative significance in determining the threat's LOF or COF. Points will be established based on criteria that the committee feels is significant to determining the threat's LOF or COF 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 susceptibility to a threat although the total points for a threat will not be less than zero.) Generally, the summation of the percentage weightings for all of the factors within each threat should be 100%. (There may be exceptions to permit the consideration of very unusual conditions.)

6.3 ***LIKELIHOOD OF FAILURE (LOF)*** is the relative measure of the probability that a pipe will fail. Failure, within the context of this procedure, is the breach of the structural integrity of the pipe. The following threat categories shall be used for calculating risk: External Corrosion (EC), Third Party (TP), Ground Movement (GM) and Design/Materials (DM). (As new credible threats are identified as relevant to the determination the LOF, they will be submitted to the Consequence Steering Committee for inclusion into the risk calculations.) Each threat category shall be weighted in proportion to PG&E and industry failure experience. EC is currently weighted 25%, TP shall be weighted 45%, GM shall be weighted 20%, and DM shall be weighted 10%.

$$LOF = 0.25EC + 0.45TP + 0.20GM + 0.10DM \qquad \text{(Equation 2)}$$

Committees used to review procedures applicable to these threats are as follows:

6.3.1 The algorithm for the threat of External Corrosion (EC) shall be calculated per the direction of the EC Steering Committee as provided in Procedure RMP-02.

6.3.2 The algorithm for the threat of Third Party (TP) shall be calculated per the direction of the TP Steering Committee given in Procedure RMP-03.

6.3.3 The algorithm for the threat of Ground Movement (GM) shall be calculated per the direction of the GM Steering Committee given in Procedure RMP-04.

6.3.4 The algorithm for the threat of Design Materials (DM) shall be calculated per the direction of the DM Steering Committee given in Procedure RMP-05.

6.4 Consequence of a Failure (COF) shall be defined as the sum of the following Consequences Categories: Impact on Population (IOP), Impact on the Environment (IOE), and Impact on Reliability (IOR). Each of the consequence categories shall be weighted in proportion to the perceived impact of a failure. IOP shall be weighted 50%, IOE shall be weighted 10%, and IOR shall be weighted 40%.

$$COF = [0.50(IOP) + 0.10(IOE) + 0.40(IOR)]FSF \qquad \text{Equation 3}$$

*Where,* *IOP* = *Impact on Population (Section 6.4.1 of this procedure)*
*IOE* = *Impact on Environment (Section 6.4.2 of this procedure)*
*IOR* = *Impact on Reliability (Section 6.4.3 of this procedure)*
*FSF* = *Failure Significance Factor, which represents the relative likelihood of leak rather than rupture and the existence of Wall-to-Wall conditions which would make the consequences of a leak more severe. The FSF will be taken as 0.5 for pipeline where the MOP is at <20% SMYS and Wall-to-Wall paving conditions are verified NOT to exist and 1.0 for pipelines where the MOP is at ≥ 20% SMYS or where Wall-to-Wall paving conditions exist or have not been verified to NOT exist. In addition, the FSF shall not be taken as less than 1.0 where the following conditions exist:*

- *Where the pipeline segment is within 300' of a School, Hospital, or Prison Building unless the outside pipe diameter is less than or equal to 4.5"*
- *Where the pipeline segment is within 300' of a switchyard.*
- *Where the pipeline was installed prior to 1947 and is in an area of ground acceleration greater than 0.5g.*
- *Where the pipeline segment was installed prior to 1947 and is in an area of ground acceleration greater than or equal to 0.2g AND is in an area of unstable soil. (Unstable soil, for the purpose of this definition, is categorized as that identified as having High/Moderate potential for liquefaction or High/Mod potential for landslide.)*
- *Where the pipeline segment has a depth of cover of less than or equal to one foot.*
- *Where the pipeline segment has a MOP of greater than 200 psig, has a outside diameter of greater than or equal to 4.5", and is Class 3.*

The weightings on each of the consequence categories will be reviewed and approved by the Consequence Steering Committee. Points will be scored to the consequences as follows:

6.4.1 Impact on Population (IOP) shall be calculated per the direction of the Consequence Steering Committee. The committee has determined that the factors in A through C of this section are significant for determining the

Population Impact of a gas pipeline failure. The IOP contribution to COF shall be the summation of assigned points times the assigned weighting for the following factors:

A) Population Density in Proximity to Pipeline (35% Weighting): Points will be awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| Class 1 | 10 | 3.5 |
| Class 2 | 40 | 14 |
| Class 3 | 70 | 24.5 |
| Class 4 | 100 | 35 |

B) Pipeline proximity[1] to a potential area of population concentration (45% Weighting): Points *are additive* and will be awarded as follows:

| Criteria | Points[5] | Contrib. |
|---|---|---|
| Identified Sites[3] that require a Integrity Management Plans: Examples include Hospitals, Schools, Childcare Centers, Retirement Communities, Prisons, Health Treatment Facilities, and Public Assembly Areas such as stadiums, churches, parks, outdoor transit terminals within the Potential Impact Radius[2] | 100 | 45 |
| Railroads, Bart, and Light Rail tracks | 30 | 13.5 |
| Highway[4] | 40 | 18 |
| Commercial Airports[6] | 50 | 22.5 |
| No Feature | 0 | 0 |

5

1 Within 100 Yards or (PIR)
2 Potential Impact Radius (PIR), (where PIR = 0.69(OD)( √MOP) (in feet)), of Pipeline centerline.
3 Identified Sites consist of facilities having persons who are confined, are of impaired mobility or would be difficult to evacuate or other identified public assembly areas where 20 or more persons congregate at least 50 days in any 12-month period. A detailed definition is provided in RMP-08.
4 Highways are Class 1, 2, and 3 roads in GIS
5 Points shall be awarded once per category. (For example, a pipe segment with two adjacent highways would be awarded 40 points.)
6 Airports must have a control tower and commercial or military traffic consisting of 1% or more of the total airport traffic.

C) Potential Impact Radius (Ft.) (20% Weighting): Points will be awarded as follows:

$$\text{Points} = 1 + \pi[(0.69)(OD^2 * MOP)^{1/2}]^2(1.3X10^{-5}), \text{ not to exceed } 20$$

6.4.2 Impact on Environment (IOE) shall be calculated per the direction of the Consequence Steering Committee. The committee has determined that the factors in A and B of this section are significant for determining the environmental impact of a gas pipeline failure. The IOE contribution to COF shall be the summation of the assigned points times the assigned weighting for the following factors:

A) Presence of a Water Crossing (20% Weighting): Points will be awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| Presence of Water Crossing | 100 | 20 |
| No Water Crossing | 0 | 0 |

B) Passing through or adjacent* to an Environmentally Sensitive Area (80% Weighting): Points will be awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| State or National Park | 70 | 56 |
| Wildlife Preserve | 70 | 56 |
| Navigable Waterway | 90 | 72 |
| Other Protected Area | 70 | 56 |
| No Environmentally Sensitive Area | 0 | 0 |

* Within 100 Yards or PIR), (where PIR = $0.685(OD)(\sqrt{MOP})$ (in feet)), of Pipeline centerline, whichever is greater and unless otherwise noted

6.4.3 Impact on Reliability (IOR) shall be calculated per the direction of the Consequence Steering Committee. The committee has determined that the factors in A though D of this section are significant for determining the reliability impact of a gas pipeline failure. The IOR contribution to COF shall be the summation of the assigned points times the assigned weighting for the following factors:

A) Reliability Impact on Customers served by CGT in the event of a pipe failure (35% Weighting): Points will be awarded for gas load[1] as follows:

Points = 10 + (Gas Load[1]/500), not to exceed 100.
Unknown Gas Load = 20.

[1] Gas Load (MCF/Day) is the higher of a Average Summer Day (ASD) or a Average Winter Day (AWD) as provided by Transmission System Planning. It does not include an Abnormal Peak Day (APD).

B) Number of Customers[1] to experience a gas service outage (55% Weighting): Points will be awarded as follows:

Points = 10 + (Customer Outages[1]/500), not to exceed 100.
Unknown Gas Load = 20.

[1] The number of customer outages is provided by Transmission System Planning.

C) Proximity of Critical Facilities (10% Weighting): Points will be awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| Liquid Fuel Pipelines[1] | 100 | 10 |
| Other Gas Pipelines[2] | 80 | 8 |
| Electric Transmission Lines[1] | 80 | 8 |
| No Critical Facilities | 0 | 0 |

1 Within 30 Meters of Gas Pipeline.
2 Within 10 Meters of Gas Pipeline.
3 The distances in footnotes 1 and 2 shown above may be adjusted as appropriate to reflect conditions verified in the field such as precise location and cover.
4 If there are multiple critical facilities, only the facility with the highest points will be counted.

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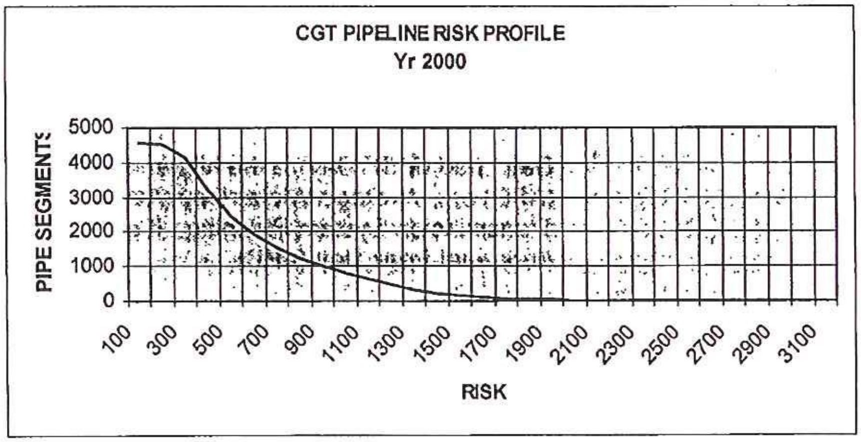
# 7.0 RISK MITIGATION

## 7.1 RISK REVIEW AND ESTABLISHMENT OF TARGET RISK THRESHOLDS

After calculating risk for all pipeline segments, a review of the risk profile is performed with a focus on high-risk pipeline facilities. A target risk threshold is established based on the risk profile and the comparative level of risk necessary to obtain confidence in the structural integrity of CGT's pipeline system. (Below is a risk profile for 2000.)




Once the threshold is established, high-risk segments are reviewed for factors that are significant risk drivers. From these, pipelines are selected for investigation, and mitigation efforts are then proposed to address the significant risk drivers. Because any pipeline failure, regardless of the consequences, is highly undesirable, it may also be prudent to select a certain number of pipelines for investigation based on a high LOF. Consideration as to the number and selection of pipelines to investigate would include the relative LOF, threat type, past risk mitigation efforts, and confidence in COF values.

Depending on the risk driver, mitigation efforts could include one or more of the following **(Note that the risk mitigation efforts discussed in this section apply to pipeline segments not covered by RMP-06. Mitigation activities for covered pipeline segments shall be performed in accordance with RMP Procedure P-6):**

- Inspections or tests to verify assumptions made in the risk calculation and integrity of the pipeline,
- Reduced operating pressure,
- Recoating
- Modification, alteration, or replacement of pipe or protective features,
- Additional Public Education as part of the PSIP Program discussed in Section 7.5 of this procedure or by additional line markers,
- Verification or modification of the consequences of a failure.

The following table provides an example of considerations that may enter into a decision process in developing a risk mitigation strategy:

| Mitigation | Risk Attributes |
|---|---|
| In Line Inspection (ILI) | EC Threat, operating at or over 30% SMYS, installed prior to 1971 and can be piggable. |
| Corrosion Survey | Pipelines that have a high consequence, high or medium likelihood of LTP, LEC and are not economical to pig. Can also be used to determine if ILI is needed. |
| Leak Survey | Pipelines that are operating below 30% SMYS and are not high LEC or LTP |
| Pressure Test | Pipelines operating at or above 40% SMYS, with high likelihood of failure due to design/material issues, and have not been hydro tested. |
| Pipe Replacement | Pipelines with high likelihood of failure that were installed prior to 1950 and cannot be economically inspected using other methods. |
| Line Marking | High LTP, low/medium likelihood for other threats. |
| Landowner Notification | High LTP, low/medium likelihood for other threats |

Risk values are reported out in a couple of different venues. They are reported to the Manager of System Integrity in an annual report, they are provided in the budgeting process to evaluate the risk benefit of performing competing projects, and summary reports are provided to regulatory agencies for their review, and, for covered pipeline segments, risk and IMA Risk (discussed in section 9.0 of this procedure) are reported in the Integrity Management Plan for each pipeline segment.

## 7.2 INSPECTION/TESTING

An effective tool in risk management is inspections and testing. Due to the serious consequences of a pipeline failure, conservative assumptions are necessarily made as to the status of a pipeline when conditions are not known. It is very common to perform an inspection and test and verify that the condition of a pipeline is much better than assumed.. The type of inspection or test specified is dependant on the threat and how the damage is manifested.

7.3 PROJECT PLANNING

RMP involvement in the Budget Planning Process also provides opportunities to reduce risk. Therefore, for each proposed project in the annual budget that is risk driven, a risk reduction calculation is performed so that an evaluation can be made as to the risk reduction benefits of the project. Often times, a project benefiting the operating capacity or operating efficiency will also reduce risk and based on a combined benefit will be the most cost effective project.

7.4 REHABILITATION

The RMP Project will propose such projects, as are necessary to establish and maintain an acceptable risk profile. In addition, the RMP will also support and propose other projects that will reduce risk where there are opportunities to justify projects based on reducing risk and reducing maintenance or operation costs. As projects are submitted for budgeting, they should be prioritized. Following is one prioritization strategy that could be used:

| Priority | Attributes |
|---|---|
| 1 | High Consequence Area (HCA)<br>Multiple Significant Risk Drivers<br>High Total Risk (> 1500)<br>>= 30% SMYS |
| 2 | Same as 1 except:<br>% SMYS < 30% or<br>Single Risk Driver > 30% SMYS in HCA |
| 3 | High Threat Risk or Total Risk (>1800)<br>Single Risk Driver<br>> 30% SMYS or < 30% SMYS w/IMA |
| 4 | High Likelihood Threat or Total Risk<br>Med/Low Consequence (Not HCA)<br>< 30 % SMYS |

Projects proposed to reduce risk shall be monitored to ensure that a reduction in risk has been obtained and that the results have been captured in the risk values.

7.5 PUBLIC SAFETY INFORMATION PROGRAM (PSIP)

The RMP will work in partnership with the Corporate PSIP Program to the extent necessary to ensure compliance with 49 CFR, 192.616 (Public Education) and 49CFR 192.615 (Emergency Plans).

49 CFR, 192.616 states "Each operator shall establish a continuing educational program to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the operator or the appropriate public officials."

49 CFR 192.615 requires establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials and training of appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective. Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to: (1) learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency; (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency; (3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property."

## 8.0 RMP MAINTENANCE

### 8.1 FACILITY UPDATE

In general, the source of information used to calculate risk shall be obtained from PG&E's Geographical Information System (GIS). Exceptions are noted within the applicable procedures. There are also special cases where updated information is made available from other sources (such as from pipeline engineers, In-Line-Inspection (ILI) reports, or Corrosion Engineers).

Changes in facility properties shall be incorporated into the Risk Calculations at least annually. Examples of facility properties include location, material properties, coating, operating status, cover, pipe specification, and structures near the facility.

### 8.2 HAZARD UPDATE

RMP will monitor industry experience, as well as PG&E experience to identify trends in threat prediction, mitigation effectiveness, and advances in inspection and risk management technology and adapt the program to new information as necessary to keep the program current and robust.

Data bases necessary for making accurate risk evaluations will be maintained and updated as necessary to ensure hazard information in current. Information necessary to accurately determine and track risk will also be updated as follows:

| Threat | Update Interval |
|---|---|
| Third Party Dig-Ins | As Submitted, Annually – Into Risk Calculations |
| Leak Reports (EC, DM) | As Submitted, Annually - Into Risk Calculations |
| Seismic (Fault Crossings) | 5 years (Per Procedure RMP-04) |
| Seismic (Vertical or Horizontal Ground Acceleration) | 5 years (Per Procedure RMP-04) |
| Slope Stability | 5 years (Per Procedure RMP-04) |
| Liquefaction | 5 years (Per Procedure RMP-04) |
| Water Crossing | 10 years |

## 8.3 CONSEQUENCE UPDATE

RMP will monitor industry experience, as well as PG&E experience to identify trends in consequence prediction and mitigation effectiveness and adapt the program to new information to keep the program current and robust.

Data bases necessary for making accurate risk evaluations and support Integrity Management activities as required by RMP-06 will be maintained and updated as necessary to ensure consequence information is current. The following Geographic information will also be updated as follows:

| Consequence | Update Interval |
|---|---|
| Electric Transmission | 10 years |
| Highways | 5 Years |
| Other (Foreign) Pipelines | 5 Years |
| Airports | 10 Years |
| Water Crossing (Navigable Waterways) | 10 Years |
| Land Base* | 5 years |
| Foot and Aerial Patrol | Annual |
| Identified Sites (as defined by RMP-08) | Annual |
| Parcel Data (as required by RMP-08) | Annual |
| Identified Sites provided by Public Safety Officials (as required by RMP-06) | Bi-Annual |

* Land Base information includes Roads, Highways, Railroads, Water Crossings (Other than Navigable Waterways), parks, etc.

## 8.4 ALGORITHM REVIEW

At least once each calendar year, the Integrity Management Group will review the threat and consequence algorithms with the appropriate steering committees and make changes as necessary to reflect regulatory requirements and best industry practices. 5

8.5 REVISION TO RISK CALCULATIONS

Risk calculations shall be reviewed annually and recalculated as necessary to reflect changes to facility, threat, or consequence data, and/or changes to the threat or consequence algorithms.

# 9.0 RISK FOR INTEGRITY MANAGEMENT

**The procedure applies to both covered and non-covered pipe segments as defined in RMP-08. In addition to the requirements specified in this procedure, RMP activities associated with covered pipeline segments must also comply with the requirements of RMP-06.**

In addition to the risk values calculated per the preceding sections of this procedure, HCA risk, as defined below, will also be calculated for all covered pipeline segments.

HCA RISK = LOF*(1+(PIR/1800)) Equation 4

Where, LOF = Likelihood of Failure based on Equation 2 of this procedure.

PIR = Potential Impact Radius as defined by RMP-08

Relative Risk Ranking is required by RMP-06 for all covered pipeline segments for the purpose of prioritizing assessments. Because the primary focus of RMP-06 and the Integrity Management Rule (covered in 49 CFR Part 192 Subpart O) is to provide personnel protection, it is necessary to remove Impacts On Reliability (IOR) and Impacts on Environment (IOE) used to calculation the Consequence of Failure given in Equation 3 of this procedure. Also, because all covered pipelines are, by definition, in High Consequence Areas, it is not necessary to consider anything more than the relative size of a failure. Therefore factoring in the size of the potential impact radius is sufficient to rank the relative Consequence of Failure for covered pipeline segments.

IMA COF = 1+(PIR/1800) Equation 5 5

PG&E's HCA risk calculation does not address two of the threats existing in a few of its covered pipelines; Internal Corrosion (IC) and Stress Corrosion Cracking (SCC). The likelihoods of failure for these threats were not included because they are currently relevant to less than 2% of the HCA pipelines. Instead pipelines with these threats were categorized as "high risk" and scheduled for assessment prior to 12/17/2007. The only exceptions are:

- 25.5 miles of Stanpac 3 with IC threat that will be MFL inspected in 2007 and
- 6442' in two DFMs that were installed between 1989 and 1994. One of the DFMs is operating under 20% SMYS and will be DA'd in 2009. The second, operating at 41% SMYS, will be smart-pigged in 2012.

Future assessments and incidents shall be reviewed to provide the input necessary to determine if these threats are more systemic and should be included in the system-wide risk calculation. The following assessments shall be performed on an on-going basis to validate the current threat assumptions: 5

For SCC:

- All direct examinations performed as part of the integrity management program shall determine, using an appropriate inspection tool, if SCC damage is present, whether the pipe segment was identified as possessing the threat or not.

For IC:

- All ILI assessments identify that identify wall loss due to IC shall determine, using appropriate inspection tool, if IC damage is actually present.
- All direct examinations performed as part of the integrity management program shall determine, using appropriate inspection tool, if IC damage is present.

If future pipeline assessments or incidents show these threats to be relevant, a separate likelihood factor shall be developed to prioritize the pipeline segments and ensure the highest risk segments are addressed first.

# 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: Dan Curtis______________________ Date: 11/21/01____
Dan Curtis

Approved By: Chris Warner______________________ Date: 11/21/01____
Chris Warner, Lead Risk Management Engineer

Approved By: Alan Eastman______________________ Date: 11/26/01____
Alan Eastman, Manager, System Integrity

| Rev. No. | Date | Description | Prepared By | Approved By | Approved<br>Manager, System Integrity |
|---|---|---|---|---|---|
| 0 | 11/26/01 | Initial Issue | DJC9 | CMW4 | ADE1 |
| 1 | 1/8/03 | Revised as Shown | DJC9 | CMW4 | ADE1 |
| 2 | 6/13/05 | Revised as shown-added section 5.0 | DJC9 | RPF2 | CMW4 |
| 3 | 10/22/05 | Revised as shown | DJC9 | CMW4 | CMW4 |
| 4 | 7/12/06 | Revised as shown | JSV2 | DJC9 | CMW4 |
| 5 | 1/14/10 | Revised as shown | KMA8 | | |

## *Table of Contents*

**1.0 PURPOSE** ........................................ **3**

**2.0 SCOPE** ........................................ **3**

**3.0 INTRODUCTION** ........................................ **3**

**4.0 ROLES AND RESPONSIBILITY** ........................................ **4**

**5.0 TRAINING AND QUALIFICATIONS** ........................................ **5**

**6.0 EC THREAT ALGORITHM** ........................................ **6**

6.1 Gas Transmission ........................................ 6

6.2 Gas Distribution ........................................ 9

# 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 and prioritize risks. That process is detailed in Section 6.2 of this document. 5

# 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)<br>• Monitor compliance to procedure – take corrective actions as necessary.<br>• Assign qualified individuals<br>• Ensure Training of assigned individuals<br>• 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.<br>• Review procedure with committee per RMP-01<br>• Provides meeting minutes<br>• Ensures action items are completed. |
| Steering Committee Members (Subject Matter Experts) | Various | • Attend meetings as requested by Steering Committee Chairman.<br>• 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<br>• Once each calendar year. |
| Steering Committee Chairman | Procedure review of RMP-01 and RMP-02 | • Upon initial assignment<br>• Once each calendar year.<br>• 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<br>• Once each calendar year.<br>• 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 | Circumferential 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.

# PACIFIC GAS AND ELECTRIC COMPANY

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

## Risk Management Procedure

Procedure No. RMP-03
Rev. 5
Third Party Threat Algorithm

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Dan Curtis,

Approved By: *Chris Warner (CMW9)* Date: 11/13/01
Chris Warner, Lead Risk Management Engineer

Approved By: *Alan Eastman (ADE1)* Date: 11/13/01
Alan Eastman, Manager, System Integrity

| Rev. No. | Date | Description | Prepared By | Approved By. | Approved Manager, System Integrity |
|---|---|---|---|---|---|
| 0 | 11/13/01 | Initial Issue | DJC9 | | Alan Eastman |
| 1 | 3/14/03 | Revised as shown | DJC9 | CMW4 | Alan Eastman |
| 2 | 6/13/05 | Revised as shown | DJC9 | CMW4 | Chris Warner |
| 3 | 10/28/05 | Revised as shown | EEM6 | DJC9 | Chris Warner |
| | | | | | Director System Integrity & Gas Issues |
| 4 | 12/27/08 | Reviewed and added DIMP | MESB | WJM8 | Bob Fassett |
| 5 | 12/28/09 | Revised as shown | | SEBE | |

## *Table of Contents*

RISK MANAGEMENT PROCEDURE .......... 1

Table of Contents .......... 2

1.0 PURPOSE .......... 3

2.0 SCOPE .......... 3

2.1 TRANSMISSION .......... 3

2.2 DISTRIBUTION .......... 3

3.0 INTRODUCTION .......... 4

4.0 ROLES AND RESPONSIBILITY .......... 5

5.0 TRAINING AND QUALIFICATIONS .......... 6

6.0 TRANSMISSION TP THREAT ALGORITHM .......... 6

7.0 DISTRIBUTION TP THREATS .......... 9

# 1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the Third Party (TP) 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 facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure.

## 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 and prioritize risks. That process is detailed in Section 7.0 of this document. 5

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## 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 Transmission Integrity Management Program (TIMP) 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, Third Party (TP).

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. TP is weighted at 45%. 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 TP, the scoring is based on direction from the Third Party Damage Committee.
The Third Party Damage 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, Third Party (TP). 5

The TP threat for distribution piping is addressed in section 7 of this document. Currently this algorithm determines the highest risk items so they can be prioritized as a group.

# PACIFIC GAS AND ELECTRIC COMPANY

ENGINEERING & OPERATIONS
GAS TRANSMISSION AND DISTRIBUTION
GAS ENGINEERING
GAS SYSTEM INTEGRITY
Risk Management

## Procedure for Risk Management

Procedure No. RMP-04
Rev. 5
Ground Movement and Natural Forces Threat Algorithm

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Approved By: *Chris Warner*____________________ Date: 11/20/01____
Chris Warner, Lead Risk Management Engineer (CMW4)

Approved By: *Alan Eastman*____________________ Date: 11/26/01____
Alan Eastman, Manager, System Integrity (ADE1)

| | | | | | Approved |
|---|---|---|---|---|---|
| Rev. No. | Date | Description | Prepared By | Approved By | Director of Integrity Management and Technical Support |
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| 4 | 12/27/08 | Added Section 6.2-Distribution Algorithm & other minor changes | CHL3 | WJM8 | RPF2 |
| 5 | 10/09/09 | Revised as Shown | CHL | [illegible] | [illegible] |

## Table of Contents

PROCEDURE FOR RISK MANAGEMENT .......... 1

TABLE OF CONTENTS .......... 2

1.0 PURPOSE .......... 3

2.0 SCOPE .......... 3

3.0 INTRODUCTION .......... 3

4.0 ROLES AND RESPONSIBILITY .......... 4

5.0 TRAINING AND QUALIFICATIONS .......... 4

6.0 GROUND MOVEMENT THREAT ALGORITHM .......... 5

6.1 GAS TRANSMISSION: .......... 5

6.2 GAS DISTRIBUTION: .......... 7

ATTACHMENT 1: FAULTCROSSINGS_2009.XLS .......... 9

ATTACHMENT 2: LEVEECROSSINGSDELTA2009.XLS .......... 9

ATTACHMENT 3: DISTIM NATURAL FORCES SME 2009 FINAL.XLS .......... 9

5

## 1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the Ground Movement and Natural Forces Threats Algorithm for the determination of Likelihood of Failure and Risk for PG&E's Gas Transmission and Distribution's Risk Management Programs (RMP) and Integrity Management Programs. 5

## 2.0 SCOPE

This guideline is applicable to all of PG&E's gas transmission pipeline and distribution facilities and is to be used in conjunction with RMP Procedure 01. The algorithm provided in this procedure is for Natural Gas Pipelines. It is not applicable to regulator, compressor, or underground 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 transmission and distribution facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure.

## 3.0 INTRODUCTION

Gas Transmission: The risk management process is a process of integrating data to calculate 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 Transmission Integrity Management Program (TIMP) 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 Transmission Integrity Management Program. This procedure supports the calculation of risk, required by Procedure RMP-01, due to one of the basic threats imposed on gas pipelines, Ground Movement (GM).

As described in RMP-01, Risk is defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF). [Risk = LOF X 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. GM is weighted at 20%. 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 GM, the scoring is based on direction from the GM Steering Committee. The GM Steering Committee shall meet once each calendar year and shall review this procedure per the requirements of RMP-01.

Gas Distribution: Gas Distribution Integrity Management Plan (DIMP) is a maturing program which will be adjusted to meet the requirements of the recently issued subpart P of 49 CFR 192. Currently it uses a Subject Matter Expert approach to identify and prioritize risks. That process is detailed in Section 6.2 of this document.

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

## 5.0 Training and Qualifications

# PACIFIC GAS AND ELECTRIC COMPANY

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

## Procedure for Risk Management

Procedure No. RMP-05
Rev. 4
Design/Materials Threat Algorithm

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Dan Curtis,

Approved By: Chris Warner__________________________ Date: 11/9/01_____
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Approved By: Alan Eastman_________________________ Date: 11/18/01____
Alan Eastman, Manager, System Integrity

| Rev. No. | Date | Description | Prepared By | Approved By | Approved |
|---|---|---|---|---|---|
| | | | | | Mgr/.Dir, GasIntegrity |
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| 1 | 11/25/03 | Revised as Shown | DJC | CMW | ADE |
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| 4 | 12/28/09 | Revised as Shown | [illegible] | SEBE | [illegible] |
| | | | | | |

## *Table of Contents*

PROCEDURE FOR RISK MANAGEMENT ........ 1

4 ........ 1

Table of Contents ........ 2

1.0 PURPOSE ........ 3

2.0 SCOPE ........ 3

3.0 INTRODUCTION ........ 3

4.0 ROLES AND RESPONSIBILITY ........ 4

5.0 TRAINING AND QUALIFICATIONS ........ 5

6.0 DESIGN/ MATERIALS THREAT ALGORITHM ........ 6

6.1 Gas Transmission ........ 6

6.2 Gas Distribution ........ 8

4

## 1.0 PURPOSE

The purpose of this procedure is to provide a guideline for determining the Design/ Materials (DM) Threat Algorithm for the determination of Likelihood of Failure and Risk PG&E's Risk Management Program (RMP) and Integrity Management Program. 4

## 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 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 CGT facilities and shall be in conformance with this procedure. The Integrity Management Program Manager shall be responsible for compliance with this procedure.

### 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 and prioritize risks. That process is detailed in Section 7.0 of this document. 5

## 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 Transmission Integrity Management Program (TIMP) 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, Design/ Materials (DM). 4

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. DM is weighted at 10%. 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 DM, the scoring is based on direction from the DM Steering Committee. The DM 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. 4
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, Design/Materials (DM).

The DM threat for distribution piping is addressed in section 7 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)<br>• Monitor compliance to procedure – take corrective actions as necessary.<br>• Assign qualified individuals<br>• Ensure Training of assigned individuals<br>• 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.<br>• Review procedure with committee per RMP-01<br>• Provides meeting minutes<br>• Ensures action items are completed. |
| Steering Committee Members (Subject Matter Experts) | Various | • Attend meetings as requested by Steering Committee Chairman.<br>• Provide review and direction to procedure. |
| Risk Management Engineers | Integrity Management Program Manager | • Perform calculations per procedure. |

4

## 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-05 | • Upon initial assignment<br>• Once each calendar year. |
| Steering Committee Chairman | Procedure review of RMP-01 and RMP-05 | • Upon initial assignment<br>• Once each calendar year.<br>• As changes are made to the procedure. |
| Steering Committee Members (Subject Matter Experts) | RMP-05 and Steering Committee requirements of RMP-01 | • Once each calendar year at the time of the steering committee meeting. |
| Risk Management Engineers | Integrity Management Program Manager | • Upon initial assignment<br>• Once each calendar year.<br>• As changes are made to the procedure. |

# 6.0 DESIGN/ MATERIALS THREAT ALGORITHM

## 6.1 Gas Transmission

Design Materials (DM) shall be calculated per the direction of the DM Steering Committee. The committee has determined that the factors in A through F of this section are significant to determining the Likelihood of Failure (LOF) of a gas pipeline due to *design/material* issues. The DM contribution to LOF shall be the summation of assigned points times the assigned weighting for the following factors:

A) Pipe Seam Design (30% Weighting): Points will be awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| Furnace Butt Weld (FBW) (Jef = 0.6) | 100 | 30 |
| Single Submerged Arc Weld SSAW (Jef = 0.8) | 60 | 18 |
| Low Freq. ERW* (Jef = 1.0) | 90 | 27 |
| A.O.Smith or Flash Weld (Jef = 1.0) | 90 | 27 |
| High Freq. ERW (Jef = 1.0) | 20 | 6 |
| Double Submerged Arc Weld (DSAW) (Jef = 1.0) | 10 | 3 |
| Seamless | 10 | 3 |
| Pre 1990 Spiral (Jef = 0.8) | 90 | 27 |
| 1990 and newer Spiral (Jef=1.) | 20 | 6 |
| Other** | 100 | 30 |
| Default (Welds made prior to 1970) | 100 | 30 |
| Default (Welds made in 1970 and after) | 20 | 6 |

* Welds made prior to 1970 using the ERW welding process are assumed to be made using low frequency.

B) Girth Weld Condition (15% Weighting): Points will be awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| Pre 1930 Girth Welds (Both Arc and oxyacetylene, regardless of seismic zone) | 100 | 15 |
| Pre 1947 Girth Welds within area of ground acceleration $\geq$ 0.2g | 100 | 15 |
| Shielded pre-1960 Bell-Spigot/BBCR** | 40 | 6 |
| Default | 0 | 0 |

** Shielded Metal Arc Welds (SMAW) made prior to 1960 or girth weld joints made with Bell-Spigot or BBCR joints.

C) Material Flaws or Unique Joints (20% Weighting): Points awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| Wrinkle Bends in Pipe w/ OD ≤ 12" | 100 | 20 |
| Wrinkle Bends in Pipe w/ OD > 12" | 50 | 10 |
| Dresser Couplings | 100 | 20 |
| Hard Spots * | 100 | 20 |
| Pre-1950 Miter Bends | 90 | 18 |
| None | 0 | 0 |

* Hard Spots point shall be awarded based on mill and age regardless of whether hard spots have been found

D) Pipe Age (10% Weighting): Points awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| Pre 1970 Pipe | 100 | 10 |
| 1970 and newer pipe | 10 | 1 |

4

E) MOP vs. Pipe Strength* (20% Weighting): Points awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| >60% | 100 | 20 |
| 50% to 60% | 80 | 16 |
| 40% to <50% | 50 | 10 |
| 30% to <40%) | 30 | 6 |
| 20% to <30% | 10 | 2 |
| Less than 20% | 5 | 1 |

4

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

F) Design/Materials Leak Rate (5% Weighting): Points awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| More than 1 leak | 200 | 10 |
| 1 leak | 160 | 8 |
| 0 leak | 0 | 0 |

1 Leaks within the last twenty years on a pipe segment or on adjacent segments with the same pipe properties and installed job or project number within a one mile radius of the leak

4

G) Test Pressure (TP)** vs. Pipe Strength* (20% Weighting): Points awarded as follows:

| Criteria | Points | Contrib. |
|---|---|---|
| TP ≥ 100%PS (test is 5 years old or less) | -200 | -40 |
| TP ≥ 100%PS (test is more than 5 years old) | -150 | -30 |
| TP < 100% PS | -50 | -10 |
| No Pressure Test or TP/MOP <1.1 | 150 | 30 |

4

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

** Pressure Tests performed earlier than 1950 will not be credited.

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### 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

Design Material (DM) (i.e. Material or Welds) 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 GM threats to the distribution system are identified by Subject Matter Experts (SME). The pool used to select the members will include Gas Engineers at PG&E, Gas Planners at PG&E, experts from the PG&E Geosciences Department, members of the PG&E System Integrity Group and other industry experts inside and outside of 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, $R = 1/n\ (\sum (L_i \times C_i))$ $(i = 1 \text{ to } n)$

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**

| MATERIAL/ WELDS | SUB-CATEGORY | THREAT | Ave Risk Rank | NOTES |
|---|---|---|---|---|
| Non Plastic | Steel | Homemade Service Tees (<60 psig) | 6.00 | |

| MATERIAL/ WELDS | SUB-CATEGORY | THREAT | Ave Risk Rank | NOTES |
|---|---|---|---|---|
| Non Plastic | | Copper, Internal corrosion - Corrosion products flake off interior walls and plug customer house lines and appliances | 9.00 | |
| Non Plastic | | Threaded Joints in distribution main | 3.60 | |
| Non Plastic | Cast Iron | Cast Iron - Bell and spigot joints prone to leakage | 3.00 | |
| Non Plastic | | Non Shielded Arc Welds | 3.00 | |
| Non Plastic | | Threaded Services | 2.80 | |
| Non Plastic | | Homemade Service Tees (>60 psig) | 2.40 | |
| Non Plastic | | Brazing Tees (>60 psig) | 1.40 | |
| Non Plastic | | Asbestos coatings - Pose a environmental and employee safety hazard. | 1.00 | |
| Non Plastic | | Oxy Acetylene Welds | 1.00 | |
| Non Plastic | | Material Defects in Steel | 1.00 | |
| Non Plastic | | Mechanical Fittings/Couplings Category 1 (seal plus resistance force on the pipe) | 1.00 | |
| Non Plastic | | Mechanical Fittings/Couplings Category 2 (seal only) | 1.00 | |
| Plastic Pipe | | Out of tolerance | 3.00 | |
| Plastic Fittings | | "MET FIT" couplings are known for failure of metal retainer band and premature leakage. | 9.00 | |
| Plastic Fittings | | Perfection/Green Risers installed between 1976 and 1979 can develop cracks in the Delrin insert allowing blow by down riser casing into surrounding soil. | 9.00 | |
| Plastic Fittings | | Risers - Insert kits are know for premature leakage at transitions or threads | 9.00 | |
| Plastic Fittings | | DuPont Aldyl- A service tees with cracking in Delrin seal due to thermal fatigue will produce leakage. | 6.00 | |
| Plastic Fittings | | Risers - "Rector Seal 5" pipe dope. This pipe dope is known to dry out and cause leaks at riser stop cock threaded joint. | 6.00 | Environmental Issue |
| Plastic Fittings | | Tee Caps – Caps can leak due to cracking from over tightening, and blow by through threads when under tightened. | 4.50 | |
| Plastic Fittings | | "AMP" valves are known for premature leaks in bonnet. | 2.50 | |
| Plastic Fittings | | "AMP FIT" compression joints are known for premature leakage. | 1.50 | H- In SF only L- Outside SF area |
| Plastic Fittings | | 1/2" CTS tees and Ells have a smaller than typical port size (0.235" compared to typical 0.375). These are mort susceptible to fouling and internal corrosion | 1.00 | |

| MATERIAL/ WELDS | SUB-CATEGORY | THREAT | Ave Risk Rank | NOTES |
|---|---|---|---|---|
| Plastic Pipe | | DuPont Aldyl A manufactured before 1973, installed from the 1960s to 1980s is vulnerable to brittle-like cracking and leakage. | 7.50 | |
| Plastic Pipe | | Pre 1960 Tenite Plastic | 1.00 | |

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

# PACIFIC GAS AND ELECTRIC COMPANY

GAS TRANSMISSION AND DISTRIBUTION
GAS ENGINEERING
GAS SYSTEM INTEGRITY
Risk Management

## Procedure for Risk Management

Procedure No. RMP-08

## Identification, Location, and Documentation of High Consequence Areas (HCAs)

Prepared By: Dan Curtis____________________________ Date: 3/1/2004____
*Dan Curtis DJC9*

Approved By: Chris Warner__________________________ Date: 3/1/2004____
*Chris Warner, Lead Risk Management Engineer CMW4*

Approved By: Alan Eastman__________________________ Date: 3/1/2004____
*Alan Eastman, Manager, System Integrity ADE1*

| Rev. No. | Date | Description | Prepared By | Approved By | Approved Mgr./Dir., Integrity Management |
|---|---|---|---|---|---|
| 1 | 5/19/04 | Revisions as Noted | DJC9 | CMW4 | ADE1 |
| 2 | 1/28/05 | Revisions as Noted | DJC9 | CMW4 | CMW4 |
| 3 | 9/28/05 | Revisions as Noted | DJC9 | CMW4 | CMW4 |
| 4 | 10/26/05 | Revisions as Noted | DJC9 | CMW4 | CMW4 |
| 5 | 9/12/07 | Revisions as Noted | WJM8 | CMW4 | CMW4 |
| 6 | 12/27/08 | Revisions as noted | WJM | WJM | RPF |
| 7 | 12/03/09 | Revisions as noted | [illegible] | [illegible] | [illegible] |

of them should be used to produce, in the judgment of the Risk Management Engineer performing the review, a reliable result Information obtained from Public Safety Officials during First Responder meetings regarding Outdoor Gathering Areas (See RMP-06 § 14.4) shall also be included during the review of HCAs. (This information may also be utilized by merging the data with parcel data or as a separate theme.) Documentation of the data used shall be as required in § 7.3 of this procedure.

Aerial and/or street based photography shall also be used to verify exclusion of pipeline segments from the integrity management rule and to identify sites that may have been missed by all of the different data sources. Items to consider include size of building, number of vehicles/ spaces available at the facility (Note that the time/day/season the aerial and/or street based photo was taken may affect the number of vehicles observed and should be taken into consideration. Recreational sites that have been missed by all of the different data souses can be identified by careful observation as to the number of vehicles in the vicinity of the pipeline.) Finally, feedback from assessment teams and personal knowledge shall be used to define HCAs.

Potential Impact Circle (PIC) is defined as:

*"Potential impact circle is a circle of radius equal to the potential impact radius (PIR).*
*Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property.*

$$PIR = 0.69 * (P * OD^2)^{1/2}$$

*Where,* *PIR* = *Potential Impact Radius in feet.*
*P* = ***MOP (Maximum Operating Pressure psi. which, for PG&E and StanPac utilization is equivalent to Regulation required MAOP or Maximum Allowable Operating Pressure)***
OD = Outside Diameter of Pipe Segment (in.)

[Note: the above formula was based on ASME B31.8S-2001 Para. 3.2. It is the same as required by 49 CFR Part 192 Subpart O §192.903(c) (issued after ASME B31.8S) with the exception that this formula requires Outside Diameter and §192.903(c) specifies nominal diameter. The difference is small and this formula is more conservative. It will therefore continue to be used to establish PIRs.]

Transmission Line is defined by CFR Part 192 Subpart A § 192.3 Definitions) as:

*"Transmission line means a pipeline, other than a gathering line, that:*
*(d) Transports gas from a gathering line or storage facility to a distribution center, storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;*
*(e) Operates at a hoop stress of 20 percent or more of SMYS; or*
*(f) Transports gas within a storage field. A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas."*

For the purpose of classifying all of PG&E and StanPac gas transmission pipelines, the Risk Management Program has defined the following as transmission:

Any pipeline segment, (other than Gas Gathering) that:

(a) Is a numbered Transmission Pipelines; or
(b) Operates at a stress (at MOP) of equal to or greater than 20% SMYS or has a downstream segment operating at 20% SMYS or more; or
(c) Transports gas to a large volume customer. (These customers are identified in GIS in the theme "All_Ncore_0903" on shared drive (Cgt on 'WalnutCrk01'\ENG\LIBRARY\GISDATA\POR\Ncorecust\All_Ncore_0903))

Pipeline Segments meeting this criteria are identified in GIS in the Pipeline Theme, (Trans_Def Field) as: "T" (meets transmission definition based on function or operating stress), "TI" (may meet transmission definition, further Investigation needed), "TC" (meets transmission definition based on function as service to large volume customer), or "TP" (defined as transmission based on stress of a pipe segment downstream operating at 20% or more SMYS. The suffix L (e.g. TL) shall be used to identify segments the state lands commission has mandated an assessment of some sort be performed. "D" shall be used for Distribution Piping and "DI" for distribution piping where some investigation of pipe properties would be useful.

## 7.0 HCA Determination

PG&E and StanPac shall use the Potential Impact Circle (PIC) method to identify HCAs (Method 2 of CFR Part 192 Subpart O § 192.903 (see Definitions). HCAs will be determined by calculating the PIC for each pipeline segment and superimposing that circle on Parcel Data and aerial and/or street based photographs to determine the potential impact of the pipeline on structures contained in the circle. The process shall be performed as follows: (Note that a flowchart showing the process details is included on page 11 of this procedure.)

7.1 Parcel Data within the PIC plus a buffer that envelopes the relevant default tolerance in Section 7.6 shall be obtained for all PG&E and StanPac transmission pipelines from appropriate county officials. This may be done by PG&E, or procured by PG&E from third party vendors (e.g. Cadastra, Michael Baker etc...) that provide this service. Transmission pipelines shall be defined by a Risk Management Engineer and Identified in GIS as described in 6.0 Definitions – Transmission Lines prior to the HCA identification. The Risk Management Engineer shall ensure that all Trans_Def Fields have been coded per the requirements of the Transmission Line definition given in § 6.0 of this procedure.

7.2 It is recommended that a join of high consequence structures obtained from Public Safety Officials and state licensing agencies and the parcel data will be performed based on street address. (Note: Although a complete match is not anticipated and a visual review is performed per Para. 7.6, any structures identified at this early stage will be helpful in providing additional assurance that these structures and sites are not inadvertently omitted from the program.) An alternative is to include this information as a separate shape file. The method used to integrate this information shall be documented as required by § 7.3. Although this work can be done by other

50' shall considered for determining whether a structure or identified site is within the PIR and should be considered an HCA.

Also, because the automated HCA process utilizes parcel boundaries rather distances to a structure, some portions of a pipeline may have been identified as being within an HCA that are not. These segments of the pipeline may be excluded from an HCA provided a manual measurement of the distance from an identified site to the pipeline is greater than the PIC or if a manual count of the number of structures within the PIC is less than 20. If a HCA is to be excluded based on distance from the structure to the pipeline, the tolerance (shown below or as discussed in the previous paragraph) shall be manually added to the PIC to account for tolerances in the location of the pipeline/imagery: (Note that, except for pipeline services to an identified site, the added tolerance need not exceed the space available for potential pipeline location error. Division Plat Sheets provide valuable information regarding the location of the pipeline with reference to the land base and should be utilized for considering the appropriate tolerance. For example, if an identified site is shown on the Plat Sheets to be on the north side of the street and the pipeline is shown in the franchise area on the north side of the street, the tolerance need not exceed the distance from the pipeline to the north edge of the franchise area.)

Default Tolerance:

- 100' – Pipeline in open country
- 40' – Pipeline in urban areas within Right of Way/Franchise Area or Street
- 15' – Pipeline GPSed

Results of the review shall be recorded by pipeline segment in the Pipeline Layer Theme (HCA_ID field) as follows:

- A - HCA based on structure Count (20 or more structures intended for human occupancy within the PIC)
- B - HCA based on both Identified Site and Structure Count
- I - HCA based on Identified Site
- N - Not an HCA (Note: When a pipe segment is identified as NOT being within a HCA, the Risk Management Engineer shall place a uniquely assigned number following the "N"[1]. The Integrity Management Program Manager shall assign unique numbers to each engineer conducting the review. Documentation of such shall be retained in the RMP Files.)
- Z - Not an HCA based on distance from the identified site to the pipeline, based on a manual structure count, or based on a reconsideration of a land use definition. (Note: these are typically where the Risk Management Engineer would like a second opinion on the exclusion of a pipe segment from the integrity management

1. The review of pipelines provides a quality assurance check of the automated GIS Tool used as a preliminary screening tool to identify covered and non-covered pipeline segments and is a check of the parcel data. Providing codes for the non-covered pipeline segments demonstrates that a qualify assurance check was performed.