PACIFIC GAS AND ELECTRIC COMPANY

CALIFORNIA GAS TRANSMISSION

GAS SYSTEM MAINTENANCE & TECHNICAL SUPPORT

SYSTEM INTEGRITY SECTION

Risk Management Procedure

Procedure No. RMP-06

Integrity Management Program
for PG&E and Standard Pacific Pipeline Inc.

			Prepared by	Approved by	Approved by	Approved by
Rev. No.	Date	Description	Integrity Management Program [redacted]	Manager, System Integrity	Director, GSM&TS	Vice President - CGT, President/CEO, Standard Pacific Pipelines, Inc.
0	12/9/04	Initial Issue	[redacted]			
1	10/14/05	See Change Forms for detailed descriptions				
2						
3						

Contents

List of Appendices

List of Illustrations

Introduction

This procedure represents the Integrity Management Program (IMP) documentation for Pacific Gas and Electric Co and Stanpac Inc, herein referred to as "Company." California Gas Transmission (CGT), the Company's business unit responsible for operating and maintaining its gas transmission facilities, developed and executes this procedure. This procedure has been designed to provide the best methods and implementation to ensure the safety of gas transmission pipelines located where a leak or rupture could do the most harm.

Corporate Philosophy

"To deliver services at the lowest possible cost without compromising safety or environmental compliance"

Integrity Management Program Ownership

The Integrity Management (IM) Program (RMP-6) shall be the responsibility of the Manager of System Integrity. Minor changes to the program can be implemented upon the authorization of the Manager. However, a new version of the program shall be issued each calendar year and approved by the Director of GSM&TS, and the Vice-President of CGT and the President/CEO of Standard Pacific Gas Line Inc. This annual process will ensure continued awareness and commitment to the Integrity Management Program.

Covered Facilities

This IM Program is applicable to all gas transmission lines operated by the Company. It does NOT apply to those facilities that are used for gas gathering or gas distribution.

CGT maintains and operates all Company facilities operating over 60 psig. All of these facilities are steel, however not all of them meet 49 CFR Sect 192.3's definition of a transmission line. The Company's interpretation of this definition was used to review all CGT maintained pipelines and determine which pipelines are covered by the rule. This delineation was noted in CGT's GIS by using the Trans_def field in the Pipeline layer. All numbered transmission lines and all other facilities operating at or above 20% SMYS were delineated as transmission. For each DFM and service operating under 20% SMYS, a visual inspection of the facility was made to determine if it was upstream of a section operating over 20% SMYS or was functioning as a transmission line and "(delivering gas primarily to)...customers who purchase it for resale". For details of the exact process, refer to Transmission Line Definition letter to Risk Management file 7.6.

Organization of IM Program

This program documentation is divided into elements applicable to each of the requirements as stated in Section 192.911 of the Subpart O-Pipeline Integrity Management. Each element is supported by documentation of the general process(es) used by the Company to comply with the requirements of that element. Procedures that give specifics of how each step of the process is conducted are provided, either as appendices or via a reference or link given to access documentation that is separate from this plan.

This IM Program is meant to provide a framework for the Company's program for integrity management, but does not repeat every element of the program that is already in place or is described by procedures with existing, readily available documentation. Where the Company has previously established and documented procedures for any part of the element, this is stated and the location of that documentation is noted. A listing of these documents as referenced throughout this IMP is presented in each Section as applicable.

Correlation with Other Company Programs

This document shows how new programs are integrated with established Company programs to address the Integrity Management Program. Among these Company programs are:

- Gas Transmission Risk Management Program
- CGT Public Safety Information Program (PSIP)
- CGT First Responder Training
- Gas Transmission Facility Geographic Information System

Use of Industry References

Several industry regulations and standards are referenced continually throughout this document. The table below lists these references and the acronym or shortened notation used to designate that reference.

Complete Reference	Listed as:	Notes:
CFR Part 192 Subpart O Sections 192.901 through Appendix E	Section or Appendix number e.g. 192.903 (1) or 192 Appendix E	Where only a section or appendix number is given, it shall be presumed that this references Subpart O
ASME/ANSI B31.8S-2001	B31.8S	Particular sections follow the general designation i.e. B31.8S 4.4
NACE RP 0502-2002	NACE RP 0502	Particular sections follow the general designation i.e. RP-0502 5.5

Training and Qualification Requirements

The provisions of this procedure shall be applied under the direction of competent persons who, by reason of knowledge of the integrity management program in the pipeline industry are qualified to review Risk and Threat Analysis on transmission piping systems. The specific qualifications are described below.

Manager of System Integrity: Shall be a degreed engineer and have gas transmission pipeline experience to provide oversight to personnel conducting Integrity Management Program process.
Training: 1. Review of RMP-06 each calendar year, NACE CP1 and RSTRENG training are desired.

Integrity Management Program Manager (IMPM): The IMPM shall be a licensed and degreed engineer with a minimum of 5 years of experience (or equivalent) performing integrity management in the pipeline industry.
Training: 1.Review of RMP-06 each calendar year, NACE CP1 & 2 and RSTRENG training are desired.

Sr. Risk Management Engineer (SRME): The SRME shall be a degreed engineer with experience performing integrity management in the pipeline industry.
Training: 1. Review of RMP- 06 calendar year, NACE CP1 & 2 and RSTRENG training are desired.

Risk Management Engineer (RME): The IMPM shall be a degreed engineer with experience performing integrity management in the pipeline industry.
Training: 1. Review of RMP- 06 each calendar year, NACE CP1 and RTSTRENG training are desired.

Corrosion Engineer (CE): The Corrosion Engineer shall be a degreed engineer with experience with corrosion control in the pipeline industry.
Training: 1.Review of RMP-06 each calendar year, 2. RSTRENG Training Course 3. CGT Corrosion Control Training Course or NACE CP-1. NACE CP2 and CP3 are desired.

PSI Program Manager: The PSIPM shall have experience with PG&E's third party public communications and awareness training, and land owner notification program.
Training: 1. Review RMP-06, Sec. 9

Qualifications and Training Requirements of other Groups supporting the Risk Management Program:

GIS Team Lead: Shall be the program lead for the GIS program.
Training: RMP-06, Sec. 2

Pipeline Engineers: Shall be a degreed engineer with transmission pipeline experience.
Training: RMP-06, Sec. 2

Mapping and Records Supervisor: Shall understand the ESC mapper's process for updating as built drawings into the GIS program.
Training: RMP-06, Sec. 12

Mappers: Shall be an ESC mapper with GIS program experience
Training: RMP-06, Sec. 2

Director of GSM&TS: Shall have authorization to approve BAP.
Training: RMP-06, Sec. 4

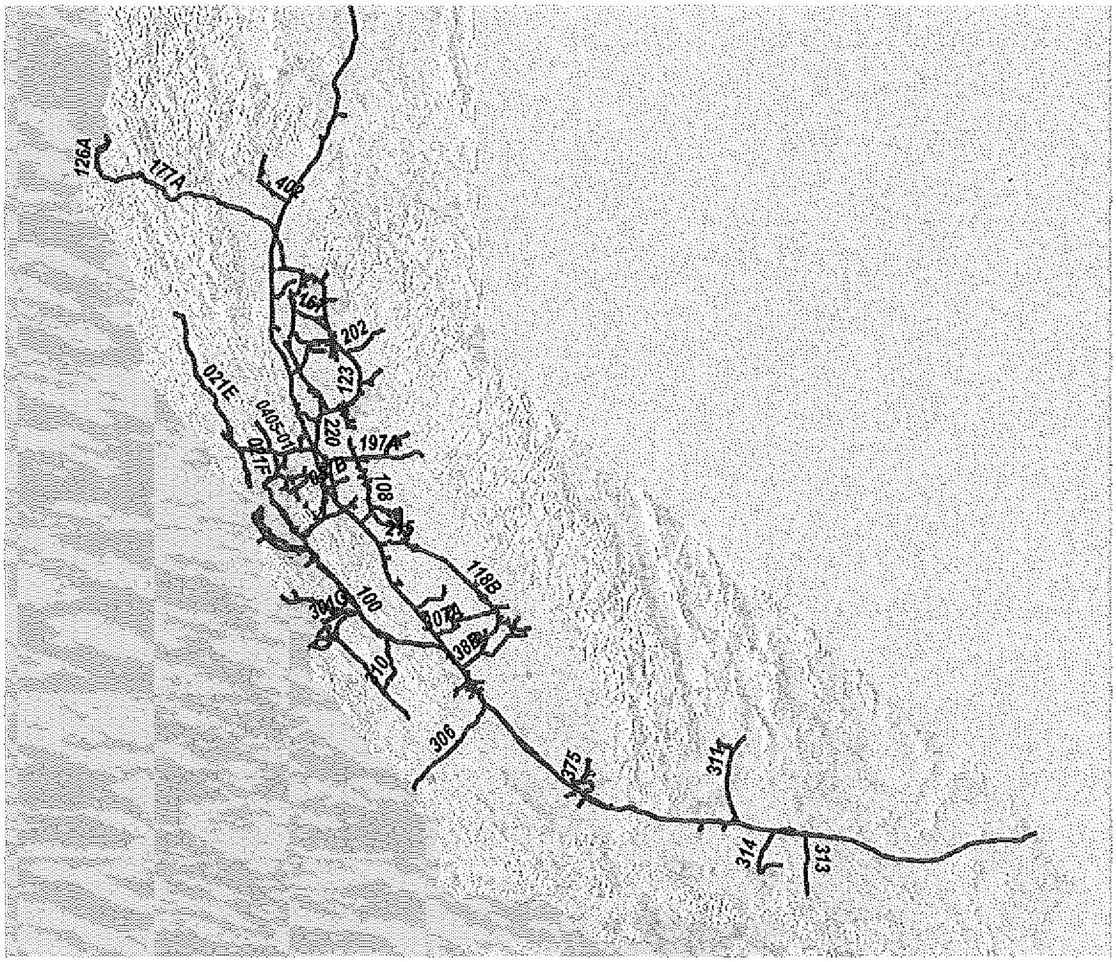
Direct Assessment Program Manager: Qualifications listed in RMP-09
Training: RMP-06, Sec. 5, 10, 12, 14

ILI Program Manager: Qualifications listed in RMP-11
Training: RMP-06, Sec. 5, 10, 12, 14

Compliance Engineer: Shall have experience with Internal Audits.
Training: RMP-06, Sec. 10

SAFETY HEALTH AND CLAIMS DEPARTMENT
Corporate PSIP Manager: Shall have experience in the company's safety program and knowledgeable with the public safety information program.
Training: RMP-06, Sec. 9

Company Transmission Facilities



The Company's transmission facilities traverse California. The extent of the Company's facilities and line numbers identifying some specific pipelines are shown on the above map.

1. HCA Identification

1.1. Scope

192.903

The integrity management regulation was designed to address areas of a pipeline that are located in high consequence areas (HCAs). HCAs are areas where a leak or failure could have a serious effect on populations or the environment. This section describes the HCA identification process for Company pipelines.

1.2. Background

Chosen Method for HCA Identification

In order to effectively manage risk, pipeline segments located within high consequence areas (HCAs) must first be identified. HCAs can be identified using two methods. Either method or a combination of both may be usedThe Company has chosen to use Method 2.

192.903 (2)

Method 2: The area within a potential impact circle containing

- An identified (Id) site or
- 20 or more buildings intended for human occupancy

Identified Sites

192.905 (b)

The location of identified sites is established from information derived from routine operation and maintenance activities and from public officials with safety, emergency response, or planning responsibilities who indicate that they know of locations meeting the identified site definition. However, the primary method of identification is from the incorporation of county parcel and the land use designation from tax roll data into the Company geographic information system (GIS).

Specifically the sources and their update frequencies include:

Public officials

- Local First Responder personnel.. http://uo/CGT/CGT_Safety/Programs/FirstRespond.htm (per section 12.8)
- Licensed daycares, elder care homes and foster homes (Ca. Social Services)..annually

- County parcel data and tax roll data…annually
- Field reports of new construction..as received
- Risk Management reports..as received

For the counties traversed by the Company's transmission lines the sources of identified sites are as follows:

County	Public Officials		Other
	First Responder Interviews*	Ca. Social Services Licensed Community Care Listing	GIS parcel & tax roll data
ALAMEDA	X	X	X
AMADOR		X	X
BUTTE	X	X	X
CALAVERAS		X	X
COLUSA	X	X	X
CONTRA COSTA	X	X	X
FRESNO	X	X	X
GLENN	X	X	X
HUMBOLDT		X	X
KERN	X	X	X
KINGS	X	X	X
MADERA		X	X
MARIN		X	X
MENDOCINO		X	X
MERCED	X	X	X
MODOC	X	X	X
MONTEREY	X	X	X
NAPA		X	X
NEVADA		X	X
PLACER		X	X
SACRAMENTO	X	X	X
SAN BENITO	X	X	X
SAN BERNARDINO	X	X	X
SAN FRANCISCO		X	X
SAN JOAQUIN	X	X	X
SAN LUIS OBISPO	X	X	X
SAN MATEO		X	X
SANTA CLARA	X	X	X
SANTA CRUZ		X	X
SHASTA	X	X	X
SISKYOU	X	X	X
SOLANO	X	X	X
SONOMA		X	X
STANISLAUS	X	X	X
SUTTER	X	X	X
TEHAMA	X	X	X
TRINITY		X	X
YOLO	X	X	X
YUBA		X	X

*These interviews may or may not encompass the entire county where the transmission facilities are located.

192.903 (2)
192.905 (a)

The Company has chosen to identify its HCAs according to **Method 2.** The Company's Pipeline layer in its GIS contains an HCA_ID field starting with one of six alpha characters designating that the transmission pipeline segment has had an HCA analysis and the result of the analysis. The alpha characters and their interpretation are as follows:

A – HCA due to 20 or more structures within the Potential Impact Circle (PIC)
B – HCA due to both identified sites and 20 or more structures within the PIC
I – HCA due to identified site within the PIC
N – Non-HCA
Z – Non-HCA after closer visual examination by engineer

The specific analyses leading to the designations in GIS, are documented in the following types of files that were created during the HCA analysis. They are available on \\Walnutcrk01\Mapping\Riskmgmt\Integrity Management Plans\HCA determination:

Tranpipe_by_County – Shapefiles of the Company facilities that were analyzed for HCAs in each county
TranpipeIZ_by_County – Shapefiles with the PIC buffer for each facility analyzed for HCAs in each county
Parcels_in_PIC_by_County – Shapefiles of the county parcels that intersected the PIC buffer for each facility analyzed in the county
HCAs_per_PICtool_by_County – Shapefiles of the GIS HCA analysis. These shapefiles are visually reviewed by qualified personnel and the Pipeline layer is edited to reflect the extents of the HCAs.

1.3. Processes for HCA Identification

192.905

The Company uses the procedure specified in RMP-08 "Identification, Location, and Documentation of High Consequence Areas (HCAs)" to identify those segments of its pipelines that are located in HCAs. A summary of the process is as follows:

1. Review landuse for parcels in transmission line PICs and enter the following data:
   - Structures – Enter maximum number of occupied structures on the parcel
   - Id Site – Enter "20" if the landuse indicates the parcel could be an identified site
2. Visually review the parcels with unclear or unknown landuse and designate the structures or presence of an Id Site.. If visual review is not performed on an unclear/unknown parcel, assume it is an identified site.
3. Utilize GIS HCA script to perform initial analysis of the pipeline segments that are located in an HCA.
4. Visually review all transmission lines to validate the GIS analysis and document the exact extent of the required assessment. Document the extent and type of HCA in the Pipeline layer.
5. Quality Assurance is required by a second risk mgmt engineer if the original analysis designated an HCA (based on a GIS HCA script) and subsequent visual analysis shows it is a non-HCA.
6. Post updates to Pipeline layer.

Procedures for these steps are listed in Subsection 1.4 Procedures.

Newly Identified Areas

192.905 (c)

When information for an area not previously classified as an HCA is received that indicates a change in conditions, this area shall be examined using Method 2 as described above. This information could be received from various sources. The most likely sources include:

- Annual parcel and tax roll data updates
- New licensed care facility in Ca. Social Services Licensed Community Care Listing
- Field reports
- Change in Class location
- Surveillance and patrolling
- Meetings with First Responder personnel (every two years)

Once an area is identified as a new HCA, it shall be incorporated into the Baseline Assessment Plan (Section 4) no later than one year from the date of identification using the procedures outlined in Section 2 of this plan. For additional information on the incorporation of new HCAs, see Section 17 "New HCA Identification" of this plan.

Removal of HCAs

In addition to supplying information about a potentially new HCA, field reports and field verification could also potentially remove an HCA. If an HCA whose status can not be annually re-verified using parcel data or aerial photographs, it shall be entered into the Annual Site Review Log for follow-up within one year to verify that it remains NOT an HCA. (One example may be a factory that is temporarily unused. During the pre-assessment of the pipeline, Field Engineers may report the building to not be in use. The parcel data may still indicate that it is a factory and the aerial photo will still show a large building. Therefore a field verification of the HCA status is required and the site must be entered in the Annual Site Review Log to ensure follow-up.)

1.4. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-08	Identification, Location, and Documentation of HCAs	As needed	RM File 7.8

1.5. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Cadastra parcel data review – letter to RM File	RM File 7.8
Landuse code designations for each county	\\Walnutcrk01\Mapping\Riskmgmt\2004 Parcel Data\ Landuse codes
Annual Site Review Log	RM File 7.8

1.6. Roles and Responsibility

Summary of the responsibilities for ensuring compliance with the element covered by this Section are as follows (more detail is contained in RMP-08):

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager System Integrity	Implementation of RMP-08
Risk Mgmt Engineers	Lead Risk Mgmt Engineers	Parcel data review and assessment of HCA extents
Public Safety Information Program Manager	Manager of System Integrity	Every two years, identified site review with First Responder personnel

1.7. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
RMP-08	Review Every 12 months and update as necessary	December 2005
Parcel and tax roll updates/changes	Annually	December 2005
Licensed Community Care listing	Annually	October 2005
New HCA assessments	Annually	December 2005
First Responder Meetings	Every two years	December 2006

2. Threat Identification: Data Integration

2.1. Scope

Potential threats to an HCA must be identified and then evaluated through a comprehensive risk analysis process. This section provides information on collecting the data that is needed to perform effective assessments.

2.2. Background

192.917

B31.8S 2.2

There are a minimum of 21 causes of gas pipeline incidents identified by the integrity management regulations and B31.8S, these are placed into nine categories, plus the category of "unknown".

Time-Dependent	1	External Corrosion	1	External Corrosion
	2	Internal Corrosion	2	Internal Corrosion
	3	Stress Corrosion Cracking	3	Stress Corrosion Cracking
Stable	4	Manufacturing Related Defects	4	Defective pipe seam
			5	Defective pipe
	5	Welding/Fabrication Related	6	Defective pipe girth weld
			7	Defective fabrication weld
			8	Wrinkle bend or buckle
	6	Equipment	9	Stripped threads/broken pipe/coupling failure
			10	Gasket O-ring failure
			11	Control/Relief equipment malfunction
			12	Seal/pump packing failure
			13	Miscellaneous
Time-Independent (includes Human Error)	7	Third Party/Mechanical Damage	14	Damage inflicted by first, second, or third parties (instantaneous/immediate failure)
			15	Previously damaged pipe (delayed failure mode)
			16	Vandalism
	8	Incorrect Operations	17	Incorrect operational procedure
	9	Weather Related and Outside Force	18	Cold weather
			19	Lightning
			20	Heavy rains or floods
			21	Earth Movements
Unknown		Unknown	22	Unknown

Since more than one threat can occur on a section of pipe, each HCA must be examined to ascertain which of these threats possibly present an element of risk to that HCA. This Section covers the process by which data is assembled for HCAs.

Section 3 "Threat Identification: Risk Assessment" discusses the method by which the HCAs are examined for each risk factor to best determine the driving risk factors for that HCA.

2.3. Company Compliance

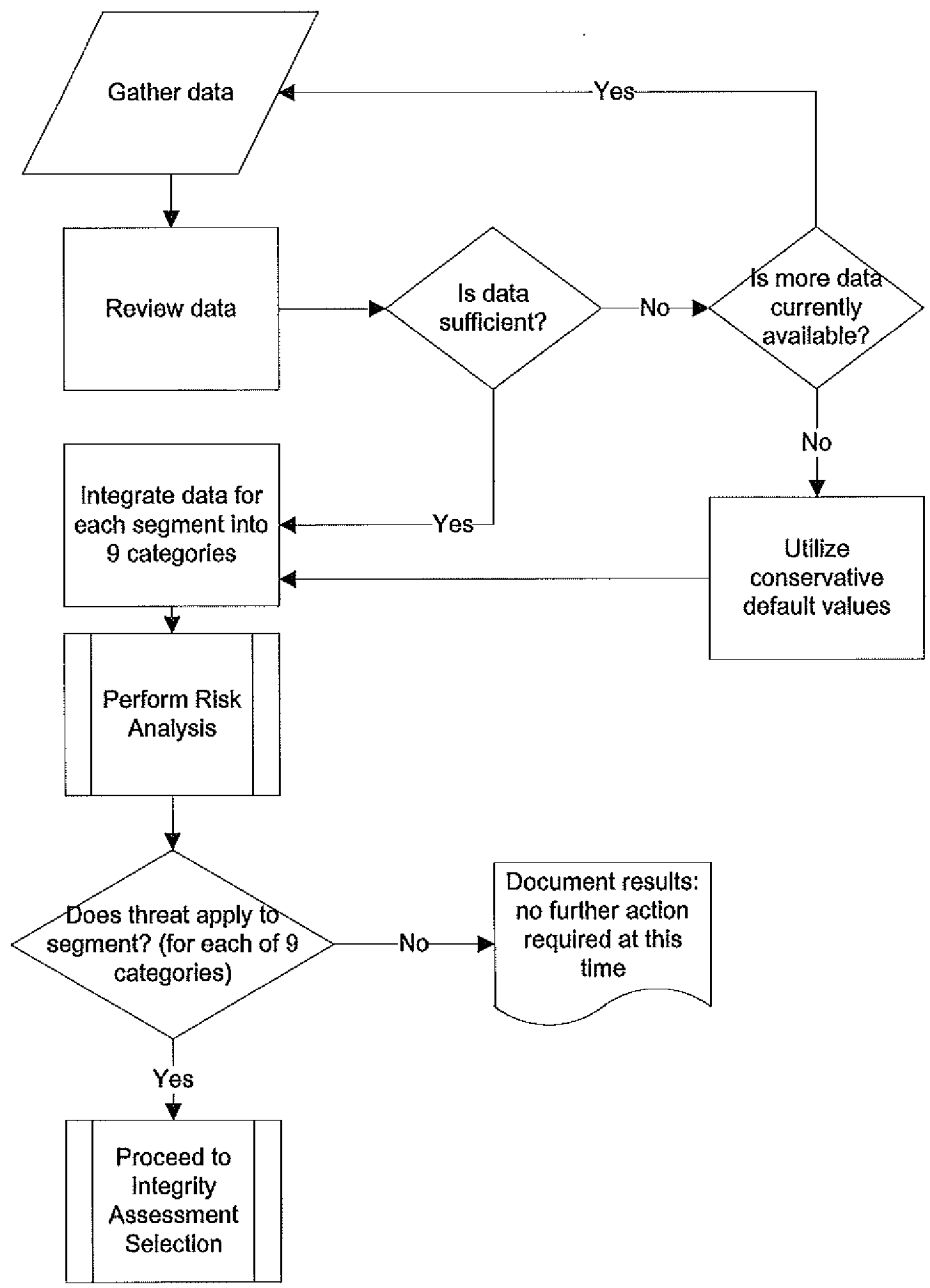
To ensure that the risk assessment and threat identification remains current, it is Company policy to perform risk assessment (per procedure RMP-01) for all transmission pipelines on an annual basis and threat analysis for all HCAs also on an annual basis. Procedure RMP-01 (Risk Management) and supporting procedures RMP-02 (External Corrosion Threat Algorithm), RMP-03 (Third Party Threat Algorithm), RMP-04 (Ground Movement Threat Algorithm), and RMP-05 (Design/Materials Threat Algorithm) provide the requirements for determining the relative risk ranking of all of the Company's transmission pipelines and serve as a basis for this procedure's description of data integration into the threat identification for HCAs.

The overall process by which the Company has chosen to comply with these requirements consists of the following steps:

1. Gather data
2. Review data
3. Integrate data to understand the condition of the pipe
4. Perform risk analysis
5. Identify the location-specific threats that could affect each HCA based on the nine categories as identified in Section 2.2 of B31.8S
   - External Corrosion Threat
   - Internal Corrosion Threat
   - Stress Corrosion Cracking Threat
   - Manufacturing Threat
   - Construction Threat
   - Equipment Threat
   - Third Party Threat
   - Incorrect Operations Threat
   - Weather and Outside Force Threat

This process is illustrated by the following flowchart.

Threat Identification and Risk Analysis Process Flowchart



2.4. Gather Data

Comprehensive pipeline and facility knowledge are essential to understanding the risk drivers that can affect an HCA. No one source of information is sufficient to make a reasonable assessment of risk; therefore, this information is gathered from numerous sources and has been integrated into the Company's GIS system.

B31.8S 4

Typical Data Elements

B31.8S Appendix A

The typical data elements used in threat identification (Excluding the Equipment Threat, which is covered by a separate procedure) are shown in Appendix B of this procedure and are documented, per HCA, in the Integrity Management Plan for each Integrity Management Area (IMA). HCAs on a pipeline are grouped into Integrity Management Areas (IMA) that can be managed and assessed together.

Data used for risk analysis can be found in Procedure RMP-01 (Risk Management) and supporting procedures RMP-02 (External Corrosion Threat Algorithm), RMP-03 (Third Party Threat Algorithm), RMP-04 (Ground Movement Threat Algorithm), and RMP-05 (Design/Materials Threat Algorithm). The data used for the risk assessment for each HCA is contained in the Risk Calculation (Walnutcrk01\Mapping\RiskMgmt\Integrity Management Plans\Threat Analysis\2004 Final Systemwide\HCApipeRisk102004.xls) and is summarized in the Pipe and Environmental Data Form in each IMA's Integrity Management Plan (see section 4.3).

Data Sources

B31.8S 4.3

Data used in threat identification shall be collected from both internal sources and external sources.

- Internal Sources include design and construction documentation and current operational and maintenance records.
- External Sources include the INGAA/AGA Vintage Pipeline report, USGS and OPS

Table 2 of B31.8S lists many of these sources. Additional sources, both internal and external, are also referenced in both the integrity management regulation and B31.8S. The B31.8S sources utilized by the Company andthe additional Company-specific sources, are presented in the following table:

Typical Data Sources		
	B31.8S Table 2	**Additional**
Internal	Pipeline alignment drawings	Existing Management Information System (MIS) databases
		Geographical Information System (GIS) databases
		Results of prior risk or threat assessments
	Pipeline aerial photography	Subject Matter Experts (SMEs)
	Facility drawings/maps	Root cause analyses of prior failures
	As-built drawings	Inspection, examination and evaluation data from integrity management implementation
		Operating History
		Current Mitigation activities
		Process and Procedure Reviews ·
	Operator standards/specifications	Maintenance Records
	Industry standards/specifications	Patrol Reports
	Inspection records	GIS Aforms
	Test reports/records	GIS Pipeline data
	Incident reports	CGT Incident Reports
	Manufacturer equipment data	

Typical Data Sources		
	B31.8S Table 2	**Additional**
External		Jurisdictional agency reports and databases including: Ground Acceleration Fault Crossings Slope Stability Liquefaction Potential Hydrology
		Navigable Waterways

Data Elements Selected for Initial Analysis

For the initial risk analysis process, the Company has chosen pipeline attributes based upon available, verifiable information or information that can be obtained in a timely manner. The data elements used in the initial analysis are identified in Procedure RMP-01 (Risk Management) and supporting procedures RMP-02 (External Corrosion Threat Algorithm), RMP-03 (Third Party Threat Algorithm), RMP-04 (Ground Movement Threat Algorithm), and RMP-05 (Design/Materials Threat Algorithm). Documentation of each data element used in the HCA Risk Calculation and the manner in which it was incorporated into the algorithms shall be developed, signed by the Risk Management Engineer, approved by the Manager of System Integrity, and retained in the Risk Management Files. Metadata for the source of each input type shall also be developed and retained in Risk Management Files for each annual HCA Risk Calculation.

Data for Future Analyses

Data integration for integrity management is an ongoing process. After the initial risk analysis and threat identification is made, re-analysis will be made on an annual basis. New or revised information regarding new pipe segments, pipe properties, pipe location, inspection information, and assessment information shall be incorporated into GIS on an on-going basis. This information will be integrated annually into the HCA Risk Calculation. New or revised information regarding environmental conditions surrounding the pipe such as ground acceleration, land base information, faults, slope stability, liquefaction, parcel data, high consequence structures etc. shall be updated as it becomes available, but at a minimum reviewed at intervals specified in Procedure RMP-01.

2.5. Review Data

B31.8S 4.3

The quality and consistency of the data must be verified once information is collected. The following issues shall be considered as data is reviewed for impact on the analysis results.

- Data resolution and units: consistency in units must be maintained
- Common Reference System: allows data elements from various sources to be combined and accurately associated with common pipeline locations
- When possible, utilize all actual data for an HCA
- Age of data: this is especially important to time-dependent threats

Insufficient Data or Poor Quality Data

This Program avoids the use of data assumptions to identify applicable threats. Missing data elements are evaluated to determine the significance of their impact to the threat analysis and any necessary default values are conservatively applied. The data for each HCA is documented in its respective Integrity Management Plan.

2.6. Integrate Data

The data elements that have been gathered from the various sources shall be integrated into GIS and a theme shall be created for use in calculating the overall risk of each HCA. Documentation of the manner in which the information was queried from GIS for linking to the appropriate HCA shall be developed and retained in Risk Management Files for each annual HCA Risk Calculation. Appendix B shows the form that details the data elements used for each HCA's risk and threat analysis. HCAs on a pipeline are grouped into Integrity Management Areas (IMA) that can be managed and assessed together. These forms will be included in the Integrity Management Plan for each IMA.

2.7. Data Configuration

The Company currently uses the following methods for data integration:

- Pipe properties (size, specification, location, inspection data, and assessment data) are updated on an ongoing basis by the Mapping Department and are stored in GIS.
- Environment Data (ground movement attributes, proximity of identified sites, proximity of land features, etc) shall be stored in GIS and shall be updated by the Integrity Management Program Manager as new information becomes available. At a minimum it is reviewed per the requirements of Procedure RMP-01.
- Data used to perform risk calculations (a result of GIS queries of applicable themes) shall be retained with the HCA Risk Calculations. This is currently in the Microsoft Excel File.

2.8. Management of Change

The Company's Management of Change process ensures that all changes to the pipeline are fully documented and tracked. This is accomplished by updating GIS on an on-going basis with new pipeline segments, incorporating relevant changes to existing pipeline information, updating environmental conditions surrounding the pipe at intervals specified in RMP-01, and recalculating risk and threat analysis annually to incorporate the changes. See Section 12 Management of Change for a description of this process.

2.9. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-01 – Risk Management	Provides requirements for the Risk Management process, update requirements for data not updated on an on-going basis by the Mapping Department, and data elements used for determining the Consequence of Failure (COF).	Reviewed each calendar year and updated as necessary.	RM File-7.1
RMP-02 External Corrosion Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to External Corrosion (LEC) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File7.2
RMP-03 Third Party Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Third Party (LTP) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File 7.3
RMP-04 Ground Movement Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Ground Movement (LGM) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File 7.4
RMP-05 Design/Materials Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Ground Movement (LGM) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File 7.5

2.10. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
HCA Risk Calculations	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Management Plans\Threat Analysis\2004 Final Systemwide\HCApipeRisk102004.xls
Risk Calculation Key/Process	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis\Risk Spreadsheet Key.xls
Threat Analysis	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis\2004 Final Systemwide\ BAPRev01 TA Current.xls
GIS Manual	\\Walnutcrk01\Mapping\RiskMgmt\Procedures\Mapper Manual (revise GSAVE man).doc
Integrity Management Plans	Risk Management Files

2.11. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Manager, System Integrity	Director, CGT Gas System Maintenance and Technical Support	Responsible for CGT Integrity Management Program. Reviews and approves all CGT Integrity Management and Risk Management Procedures
Integrity Management Program Manager	Manager, System Integrity	Responsible for CGT Risk Management Program (RMP-01, RMP-02, RMP-03, RMP-04, and RMP-05), GIS data quality and data integration, Metadata on data sources, threat identification, assessment selection (this procedure), obtaining and updating GIS to reflect HCA's from outside commercial and jurisdictional databases. Responsible for reviewing and approving Risk Management Procedures, and Integrity Management Program Procedure.
Mapping & Records Supervisor	Manager, Operations Support	Responsible for maintaining accurate and current pipeline information in GIS.
Mappers	Mapping & Records Supervisor	Responsible for maintain CGT's GIS as a current record of its pipeline facilities. Maintenance is performed by utilizing records from various sources including; Construction "As-Builts", Inspection and Leak reports, "New Construction along Pipeline" reports, and continually aligning facilities to GPS reads taken by field personnel
GIS Team Lead	Integrity Management Program Manager	GIS Program Development and Maintenance for CGT Gas System Maintenance and Technical Support
Public Safety Information Program Manager	Manager of System Integrity	Updating GIS to reflect HCA's identified by Public Safety Officials, Third Party Dig-In concerns identified by the districts, and Public Education Efforts to reduce the likelihood of Third Party damage.
Pipeline Engineers	Manager, Pipeline Engineering	Submit notification of landslide or erosion concerns.

2.12. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Threat identification	Annually	12/2005

3. Threat Identification: Risk Assessment

3.1. Scope

Potential threats to an HCA must be identified and then evaluated through a comprehensive risk analysis process. This Section covers the process by which HCAs are examined for each threat to best determine the driving risk factors.

3.2. Background

There are a minimum of 21 causes of gas pipeline incidents identified by integrity management regulations and B31.8S, which are placed into nine categories plus the category of "unknown." See Section 2 Threat Identification: Data Integration for a description of these threats and the data elements selected to perform the initial risk analysis and threat identification.

Since more than one threat can occur on a section of pipe, each HCA must be examined to ascertain which of these threats possibly present an element of risk.

3.3. Risk Assessment

192.917 (c)

Risk assessment is performed per RMP-01. The RMP-01 methodology looks at all threats for which meaningful data is available. Including threats where meaningful data is not available will mask the significance of those threats which can be more precisely defined. As better data becomes available for threats not currently included in RMP-01, that procedure will be updated to include them. This risk assessment provides a method to prioritize HCAs for the baseline assessment schedule as well as providing the information needed for effective preventive and mitigative actions. Assessment also helps determine modified inspection intervals for continued re-assessments and whether or not alternative inspection methods are needed.

Risk assessment provides a rational and consistent method to make determinations about the integrity of a pipeline segment and allows more effective use of resources in both identifying and mitigating threats. Effective data integration combined with assessment identifies the scenarios more likely to occur and prevents focusing on improbable catastrophic events.

3.4. Risk Definition and Computations

Risk can be described as the product of "likelihood" and "consequence". Risk Analysis is performed per procedure RMP-01 for all transmission pipelines. The method described in the procedure is a relative risk ranking approach with Subject Matter Experts providing input and direction as to the algorithms used to perform the computations.

Steering Committees have been established and meet each calendar year to review the algorithms and consider changes to improve the accuracy of the algorithm results. The membership and minutes from the meetings are documented in the Risk Mgmt Library, File 4.0. The established Steering Committees include;

- Consequence Steering Committee with oversight of RMP-01 (Risk Management),
- External Corrosion Steering Committee with oversight of RMP-02 (External Corrosion Threat Algorithm),
- Third Party Steering Committee with oversight of RMP-03 (Third Party Threat Algorithm),
- Ground Movement Steering Committee with oversight of RMP-04 (Ground Movement Threat Algorithm), and
- Design/Materials Steering Committee with oversight of RMP-05 (Design/Materials Threat Algorithm)

3.5. Threat Analysis

Threat Analysis shall be performed for all covered pipeline segments integrating information from Risk Analysis for both covered and non-covered pipeline segments as follows

External Corrosion: The External Corrosion Threat was assumed to exist on all CGT pipelines. Information integrated into the risk calculations required to comply with RMP-02 and used to weight the relative significance of the threat include:

- Past Corrosion Surveys,
- Visual Inspection of Coating,
- Presence of Casings,
- Past ILI,
- EC Leak Experience,
- Coating Type,
- AC/DC Interference,
- Coating Age,
- MOP vs. Pipe Strength,
- Visual Inspections of Pipe,
- Pressure Testing, and
- Past ECDA. Also included, to meet these requirements, is pipe Outside Diameter, Wall Thickness, MOP

It should be noted that, inspection data and leak experience on adjacent pipeline segments, whether HCA or not, shall be considered in the quantification of Likelihood Of Failure (LOF) due to external corrosion.

Internal Corrosion: Internal Corrosion threat is known to exist if an internal corrosion leak has occurred in the vicinity of the HCA or if in the threat exists in the judgment of the Senior Corrosion Engineer. The Senior Corrosion Engineer shall perform this system-wide analysis and specify where the threat is known to exist

Internal corrosion is a possible threat for the remaining pipeline so additional data integration will occur during the pre-assessment and direct examination phases of ECDA, in order to determine if the threat exists. The additional data integration includes:

- During pre-assessment, historical records, operating history and the experience of field personnel will be researched. If pre-assessment reveals the potential for internal corrosion, ICDA will be performed to assess the HCAs affected.
- During direct examinations, ultrasonic wall thickness reads will be taken at the bottom of the pipe, if internal corrosion is discovered ICDA will be performed to assess the affected HCAs.

Stress Corrosion Cracking: The Stress Corrosion Cracking (SCC) Threat shall be assumed to exist if SCC has been experienced (determined by a leak, Pressure Test Failure, or inspection) on any pipeline segment with similar pipe properties and operating conditions or if all of the following conditions are present:

- Operating stress > 60% SMYS
- Distance from compressor station ≤ 20 miles
- Coating system other than fusion bonded epoxy (FBE)

Manufacturing Threat: The Manufacturing Threat shall be assumed to exist if the HCA meets one of the two following criteria.

1. If the pipe segment is a) Cast Iron, b) installed more than 50 years ago, c) joined with acetylene welds, d) joined with mechanical couplings, or
2. If the pipe segment has a Joint Efficiency Factor of less than 1.0 or is manufactured with Low Frequency ERW or Flash Welded Pipe (assumed to be pipe installed with ERW, Flash Weld, or Unknown Seam prior to 1970).

Construction Threat: Due to the concern for potentially non-ductile girth welds, it shall be assumed that the Construction Threat exists for all HCAs installed prior to 1947.

Equipment Threat: (In Preparation, to be provided by Subject Matter Expert by 12/05)

Third Party Threat: The Third Party Threat shall be assumed to exist for all HCAs. Information integrated into the risk calculations documented in RMP-03 and used to weight the relative significance of the threat include:

- Feedback regarding pipelines particularly vulnerable to dig-ins
- Class Location
- Damage Prevention Measures (Standby/Aerial Patrol/None)
- Ground Cover (from inspection reports and GIS)
- Pipe Diameter
- Wall Thickness
- Line Marking
- MOP vs. Pipe Strength
- Third Party Leak History
- Public Education efforts in the area.

It should be noted that, inspection data and leak experience on adjacent segments, HCA or not, shall be considered in the quantification of Likelihood Of Failure (LOF) due to a third party.

Incorrect Operations Threat: The Incorrect Operations Threat was assumed to exist for all HCAs.

Weather and Outside Forces Threat: The Weather and Outside Forces Threat shall be assumed to exist if HCA meets any of the following criteria:

- Is in an area of potential ground acceleration greater than 0.2g
- Crosses a Historic or Holocene Earthquake Fault
- Crosses a navigable waterway
- Erosion has been identified
- Landslide has been identified
- Is in an area of High/Moderate Slope Instability
- Is in an area of Known or High/Moderate potential for liquefaction in combination with ground accelerations equal to or greater than 0.2g.

Hard Spot Threat : The Hard Spot Threat shall be assumed to exist if the HCA meets the following criteria:

Operates at a stress greater than 50% SMYS (based on MOP) and has one of the following seam types:

- Unknown seam type installed between 1947 and 1960,
- Flash Welds from AOSmith or unknown manufacturer installed between 1952 and 1957,
- DSAW Welds from Bethlehem, Kaiser, Republic or unknown manufacturer installed between 1949 and 1957,
- ERW Welds from Youngstown Sheet and Tube or unknown manufacturer installed between 1947 and 1960.

Documentation: Results of the Threat Analysis and relevant data for each HCA shall be included in the respective Integrity Management Plan (see Section 4.3). Appendix C of this procedure provides a Typical Threat Analysis Sheet.

3.6. Management of Change

Company's Management of Change process ensures that all changes to the pipeline are fully documented and tracked. This is accomplished by updating GIS on an on-going basis with new pipeline segments, incorporating relevant changes to existing pipeline information, updating environmental conditions surrounding the pipe at intervals specified in RMP-01, and recalculating risk and threat analysis on annually to incorporate the changes. See Section 12 Management of Change for a description of this process.

3.7. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-01 – Risk Management	Provides requirements for the Risk Management process, update requirements for data not updated on an on-going basis by the Mapping Department, and data elements used for determining the Consequence of Failure (COF).	Reviewed each calendar year and updated as necessary.	RM File-7.1
RMP-02 External Corrosion Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to External Corrosion (LEC) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.1

RMP-03 Third Party Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Third Party (LTP) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.2
RMP-04 Ground Movement Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Ground Movement (LGM) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.3
RMP-05 Design/Materials Threat Algorithm	Provides requirements for determining the Likelihood of Failure due to Ground Movement (LGM) algorithm and the data elements that are used for making the determination.	Reviewed each calendar year and updated as necessary.	RM File-7.4

3.8. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
HCA Risk Calculations	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Management Plans\Threat Analysis\2004 Final Systemwide\HCApipeRisk102004.xls
Risk Calculation Key	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis\Risk Spreadsheet Key.xls
Threat Analysis	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis\2004 Final Systemwide\HCApipeRisk102004 Threat Values3BAPRev01 TA Current.xls
Integrity Management Plans	Risk Management Files

3.9. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Manager, System Integrity	Director, CGT Gas System Maintenance and Technical Support	Responsible for CGT Integrity Management Program. Reviews and approves all CGT Integrity Management and Risk Management Procedures
Integrity Management Program Manager	Manager, System Integrity	Responsible for CGT Risk Management Program (RMP-01, RMP-02, RMP-03, RMP-04, RMP-05, and this procedure), GIS data quality and data integration, Metadata on data sources, Supervises Threat Identification and Risk Analysis,

		Assessment Selection (this procedure), Responsible for reviewing and approving Risk Management Procedures, and Integrity Management Program Procedure.
Sr. Risk Management Engineer/Risk Management Engineer	Integrity Management Program Manager	Perform Risk Computations and Threat Analysis per procedure. Report results.

3.10. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Risk Calculations	Annually	12/05

4. Baseline Assessment Plan

4.1. Scope

192.921(d)

A Baseline Assessment Plan (BAP) provides the initial schedule for the assessment of all HCAs. This Section outlines the process and requirements for scheduling these assessments.

4.2. Background

Those HCAs with the highest potential for risk are given priority. At least 50 percent of the HCAs must be completed by December 17, 2007 and the remainder must be completed by December 17, 2012.

Bulletin 111703

In addition, operators must have started the initial assessment by June 17, 2004.

192.921(f)

The Baseline Assessment on newly identified HCAs must be completed within 10 years from the date the area is identified. Section 17 of this manual addresses new area identification.

192.919

The Company's Baseline Assessment Plan is documented through the combination of the Company's approved BAP list, integrity management plans for each IMA, risk management procedures and its Integrity Management Assessment Computer System (IMACS).

The approved BAP list is a signed and approved listing containing the following:

- HCAs identified by pipeline, segment number, starting and ending mile points
- Type of HCA: A – 20 or more structures, I – Identified site, B – Combination
- Risk assessed for each HCA
- Threats identified for each HCA
- Planned assessment method
- Planned assessment year

The approved BAP list is located in the RM File 7.6 as a supplement to this procedure.

The integrity management plans cover the following elements:

- The potential threats affecting the HCAs in an Integrity Management Area (IMA).
- The method(s) selected to assess the integrity of the HCAs in each IMA. These may include:
  - Internal inspection tools (ILI)
  - Pressure testing
  - Direct assessment
  - Other technology
- The specific threats for each HCA in the IMA
- The assessment methods and reasons for selecting the methodology

Risk management procedures cover:

- Establishment of a direct assessment plan…RMP-09 "Procedure for External Corrosion Direct Assessment"
- Procedures to ensure that the assessments are done with minimal environmental and safety risks are included in the RMP-09 "Procedure for External Corrosion Direct Assessment" and RMP-11 "Procedure for In-Line Inspections"

The Integrity Management Assessment Computer System (IMACS) provides:

- Work management of scheduled integrity assessment efforts
- Summary reports of the IMA assessment schedules, assessment methods and identified threats.

4.3. Company Compliance

The overall process to develop Company's BAP is as follows:

1. Identify and prioritize threats using Risk Analysis Procedure(s) results. Section 3 Threat Identification: Risk Assessment describes the procedures for threat identification and ranking.

2. Risk rank the HCAs and prioritize assessments ensuring that risk and operational feasibility are considered. Risk ranking will occur as follows:
   - Calculate the risk for each HCA per RMP-01.
   - Determine the high risk HCAs. High risk HCAs are those with:

     A risk of one standard deviation above the median (29.83). In addition, all HCAs with a risk between the median and one standard deviation are further analyzed to determine if they are high risk. Those operating at or above 50% SMYS and above the median (22.52) are defined as high risk. Those operating above 30% SMYS and with a risk greater than the median minus one standard deviation (15.21) with a poor pipe condition report or third party or external corrosion report in the last 20 years are also defined as high risk.

     In addition, where threats of a manufacturing or construction defect, including seam defects, in a covered segment are identified and any one of the following conditions occur, the segment shall be considered a high risk segment in the baseline assessment plan or in any subsequent assessment.

     (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

     (ii) MOP increases; or

     (iii) The stresses leading to cyclic fatigue increase.
   - Assign a preliminary time period for which the HCA should be assessed (first 5 years "high risk" or second 5 years "low risk"). Develop integrity management areas (IMA) that are groups of HCAs that will be assessed and managed in one plan. Pipelines may need to be divided into two or more IMAs to enable high risk HCAs to be assessed in the first 5 years and allow lower risk HCAs to be postponed until the second 5 years.
   - Establish an assessment schedule within the five year time periods that will, to the greatest extent practicable, efficiently utilize assessment resources to ensure that most of the high risk HCAs are assessed by 12/2007.

Note: for HCAs with IC threats, since the risk algorithm does not include an internal corrosion component, assessments shall be scheduled to occur during the first five years, unless the pipe in the HCA is less than 20 years old, has no history of internal corrosion leakage, and operates under 50% SMYS.

3. Determine best assessment method(s).

4. Schedule assessments to meet compliance dates.

5. Upload the assessment information into IMACS, the Company's Integrity and Risk Management schedule tool.

6. Print summary BAP report detailing, for each year, the IMAs to be assessed, the proposed assessment methods, and identified threats.

7. Have summary BAP approved by appropriate Company officials; document approval process and date.

8. In addition to the above, it is the responsibility of the Integrity Management Program

Manager to provide an Integrity Management Plan (IMP) for each IMA. The plan shall contain details of the pipe and environmental properties (discussed in section 2), threat analysis consideration (discussed in section 3), and risk analysis results (also discussed in section 3), assessment plan (per this section), and the Long Term Integrity Management Plan (LTIMP discussed in Section 7). The IMP and the BAP shall be maintained concurrently.

4.4. Prioritize Assessment Schedule by Risk

B31.8S 5.10

Assessments of the HCAs in an IMA shall be scheduled per 4.3.2 of this procedure.

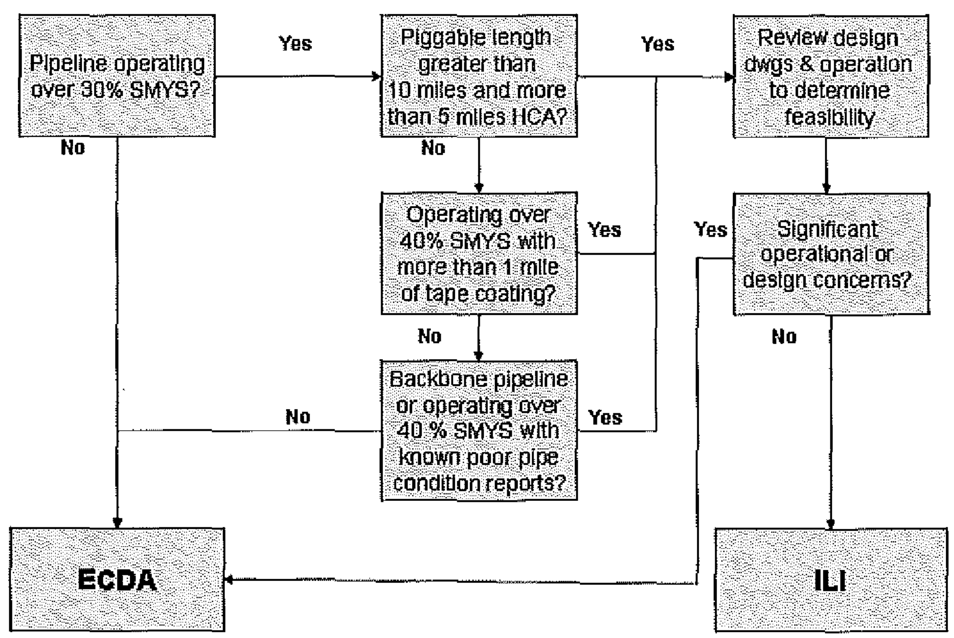
4.5. Selecting the Best Assessment Method(s)

192.919 (b)

Scheduling integrity assessments for risk must also take into account the type of assessment method(s) that will be used in order to provide a BAP that is both comprehensive and practical. The methods chosen are based on the threats identified in the risk assessment procedure. More than one assessment method may be required to adequately cover the potential risks of an HCA. Guidelines as listed in Appendix A of B31.8S shall be used to make that determination.

For the two primary assessment methods, ILI and DA, the following flowchart describes the high level process for selecting the appropriate method.

Tool Selection Process
ILI vs. DA



material redacted

GTR0005752

4.6. Use of Prior Assessments

192.921(e)

Assessments made before December 17, 2002, may be used as baseline assessments if the integrity assessment meets the baseline requirements of Subpart O and the operator has taken subsequent remedial actions to address the conditions that are listed in §192.933. The re-assessment of these HCAs must be done **no later than** December 17, 2009. There are only a few IMAs containing HCAs whose prior assessments will be utilized. These HCAs are documented in GIS and IMACS, and the IMA's integrity management plan documents the assessment type and date, the results of the assessments and the long term integrity plan.

4.7. Direct Assessment Plan

Depending on the threat addressed, direct assessment may be needed. See Section 5.6 for the Direct Assessment Plan.

4.8. Additional Considerations for Assessment Scheduling

The risk factors considered in scheduling shall be documented. See Sections 2 and 3 on data integration.

192.921(g)

Newly installed pipe that are HCAs or newly identified HCAs must be scheduled for assessment within 10 years from the date the pipe is installed or the new HCA identified. For new pipe, a post-installation pressure test per subpart J of 192 can be used as the baseline assessment. An operator must use the test pressures specified in Table 3 of Section 5 of B31.8S to justify an extended re-assessment interval in accordance with §192.939.

192.919(e)

The baseline assessment must be done in a manner that minimizes environmental and safety risk. Section 16 describes the Company program for ensuring this occurs.

4.9. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09 "External Corrosion Direct Assessment Procedure"		As needed	RM File 7.9
RMP-11 "Procedure for In-Line Inspections"		As needed	RM File 7.11

4.10. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Baseline Assessment Plan List	Risk Mgmt File 7.6
Integrity Management Plans	Risk Mgmt Files

4.11. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager – System Integrity	Oversees development of BAP and oversees and approves development of Integrity Management

		Plans. Can also prepare and revise these plans.
Senior Risk Management Engineer and Risk management Engineer	Integrity Management Program Manager	Under the direction of the Integrity Management Program Manager, prepares and revises BAP and Integrity Management Plans.
Manager – System Integrity	Director – GSM&TS	Approves BAP. Can also prepare, revise and approve changes to IMPs.
Director – GSM&TS	VP – CGT	Approves BAP
VP – CGT	Sr. VP – Utility	Approves BAP and annually authorizes changes

4.12. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Initial BAP completed	Reviewed annually for additions. On-going updates as assessments results establish re-assessment intervals.	December 17, 2004
Complete baseline assessment forat least 50% of HCAs including the highest risk HCA's.	December 17, 2007	Varies; re-assessment based on method and conditions of segment
Complete baseline assessment on remaining 50% of HCAs	December 17, 2012	Varies; re-assessment based on method and conditions of segment

5. Integrity Assessment including the Direct Assessment Plan

5.1. Scope

This Section describes the tools and methods selected to assess pipeline integrity and the process by which the assessment results are collected and integrated with other data.

5.2. Background

192.921

The Company will choose the method or methods best suited to assess the identified threats to the HCA. These methods may include:

1. In-line inspection tools (ILI) per RMP-11 which may include;
   - Metal loss tools for external and internal corrosion
   - Crack Detection tools for Stress Corrosion Cracking (SCC)
   - Metal loss and caliper tools for third party and mechanical damage
   - MFL tool to measure residual magnetism to assess areas with different hardness
2. Pressure testing
3. Direct assessment
   - External Corrosion Direct Assessment (ECDA): per RMP-09
   - Internal Corrosion Direct Assessment (ICDA): under development
   - Stress Corrosion Cracking Direct Assessment (SCCDA) under development
   - Confirmatory Direct Assessment (CDA): under development

Other technology may be used that provides an equivalent understanding of the pipeline condition. If used, the Office of Pipeline Safety (OPS) and the CPUC must be notified 180 days before conducting the assessment. See Section 15 "Notification of Authorities" for the notification procedure.

Other processes may also be used depending on the type of threat(s) to which the pipeline is susceptible. These include surveys to consider such factors as land movement, pipe movement, outside forces, welding procedure reviews and visual inspection reports.

5.3. Company Compliance

The Company Procedures and Standards detailing the process for appropriately utilizing the approved assessment methodologies are as follows:

- **ILI**...RMP-11
- **Pressure Testing**...GS&S A-37
- **ECDA**...RMP-09
- **ICDA – To be developed by 12/05**
- **SCCDA – To be developed by 12/05**

5.4. Inline Inspection

It is the Company's desire to inspect pipelines utilizing In-Line Inspection (ILI), whenever it is physically and economically feasible. Some of the considerations used to determine feasibility include:

- Minimum length of at least 10 miles, that is predominately located in HCAs
- Less than 0.5 miles of replacement required to make the pipeline piggable
- Flow rates that enable a successful ILI
- Pipeline operation over 30% SMYS

For a high level flowchart of the decision making process see section 4.5.

5.5. Pressure Testing

The Company does not plan to use pressure testing to assess the integrity of its pipelines, unless it is a post installation test or up-rate test for a new HCA. However, during the course of assessing data for ECDA or ILI, it may become apparent that pressure testing is the only feasible option. If so, the Company will perform a pressure test following the requirements found in Company's Gas Standards and Specifications A-37.

5.6. Direct Assessment

192.923

Direct Assessment assesses integrity by the use of a structured process to integrate knowledge of the physical characteristics and operating history of a pipeline with results of inspection, examination and evaluation. It can be used as a primary method only for external and internal corrosion, and stress corrosion cracking. It may also be used as a supplement to other methods.

External Corrosion Direct Assessment (ECDA)

192.925
B31.8S 6.4
NACE RP 0502

External Corrosion Direct Assessment is one method that may be used to determine the threat of external corrosion on the integrity of an underground pipeline. The focus of the ECDA approach is to identify locations where external defects may have formed; however, it may also detect evidence of such threats as mechanical damage. ECDA, as described in Appendix B of B31.8S can be used as an initial baseline inspection.

ECDA uses non-intrusive (above ground or indirect) examinations to estimate the success of corrosion protection. Excavations are made to confirm the ability of the indirect examinations to locate active and past corrosion and areas of significant coating damage. Then post assessments are made to determine re-inspection intervals and assess performance measures.

ECDA must meet the requirements of 192.925, of B31.8S Section 6.4 and NACE RP 0502. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information to evaluate the HCA for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

The Company procedure RMP-09 details the processes and requirements for ensuring an effective ECDA. The Company participated with OPS and Keyspan Energy to produce the ECDA video that has been used to communicate the process. A summary of the process is as follows:

NACE RP 0502 Section 3

ECDA is a four-step process.

1. **Pre-assessment:** provides guidance for selection of the pipeline segment and which indirect methods to used. Also identifies ECDA regions (refer to RMP-09 for definition of ECDA Regions), areas within a pipeline segment that are suitable for the same indirect exam methods.

NACE RP 0502 Section 4

2. **Indirect Examination:** indirect aboveground electrical surveys are performed to detect coating defects and the level of cathodic protection. A minimum of two complimentary survey processes is required. The results of these surveys are weighed against established protocols to identify and prioritize locations for direct examination.

NACE RP 0502 5

NACE RP 0502 5.5.2.2

3. **Direct Examination:** excavations expose the pipe surface for metal-loss measurements, estimated corrosion growth rates, and measurements of corrosion morphology estimated during indirect examination. This step collects information to characterize any corrosion defects present and confirms the ability of non-intrusive inspections to locate active and past corrosion on a pipeline.

NACE RP 0502 Section 6

NACE RP 0502- Appendix D

4. **Post Assessment and Continuing Evaluation:** sets re-inspection intervals, provides a validation check, and provides performance measures. Intervals are determined by the number of excavations made as well as the repair activity and the operating pressure of the segment. The validation check consists of at least one additional excavation performed at the location estimated to contain the next most severe defect not previously subjected to direct examination.

Internal Corrosion Direct Assessment (ICDA)

192.927

B31.8S 6.4 and Appendix B2

Internal corrosion is most likely to occur where water first accumulates. Internal Corrosion Direct Assessment (ICDA) is a method that can assess for this threat on segments that normally carry dry gas but may have short term upsets of wet gas or free water (or other electrolytes) which may accumulate in low points or inclines. It is not to be used on segments where electrolyte is nominally present in the gas stream unless an ICDA plan is developed for that specific situation that effectively addresses internal corrosion and notification is provided in accordance with §192.921 (a)(4) or §192.937(c)(4).

The process identifies areas where fluids are likely to reside, then focuses direct examination on those areas, followed by post-assessment evaluation and monitoring.

ICDA must meet the requirements of 192.927 and B31.8S Section 6.4 and Appendix B2. The Company is currently developing its ICDA procedure. This procedure will comply with NACE requirements and will include the following steps:

ICDA is a four-step process.

1. **Pre-assessment:** gathers information to evaluate the feasibility of ICDA and a model to identify entrainment areas and ICDA regions.

2. **ICDA Region identification:** consists of the entire areas along a pipeline where internal corrosion may occur starting from the location where liquid may first enter. An ICDA Region may include one or more HCAs.

3. **Identification of locations for excavation and direct examination:** performed where electrolytes are most likely to occur and at least one excavation in an HCA.

4. **Post-assessment evaluation and monitoring:** validates the ICDA process using one or more additional digs at predicted water accumulation sites with inclination angles greater than the critical angle.

Stress Corrosion Cracking Direct Assessment (SCCDA)

Stress Corrosion Cracking Direct Assessment is one method that may be used to determine the threat of stress corrosion cracking on the integrity of an underground pipeline. The focus of the SCCDA approach is to identify locations where SCC may have formed; however, it may also detect evidence of such threats as mechanical damage.

SCCDA is being developed as a NACE procedure and a corresponding Company procedure will be issued when this is available. The Direct Assessment Program Manager is responsible for developing this procedure by 12/31/2005, so that it can be used for planned SCC assessments in 2006.

Direct Assessment as a Supplemental Method

192.923(c)

If Direct Assessment is used as a supplemental assessment method, it must follow the requirements of 192.931. See Section 8 Confirmatory Direct Assessment for more information.

5.7. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09	External Corrosion Direct Assessment Procedure	As Needed	RM File 7.9
RMP-11	In-Line Inspection Procedure	As Needed	RM File 7.11
GS&S A-37	Hydrostatic Testing Procedure	As Needed	Tech Info library

5.8. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Field Engineer Process (under development)	

5.9. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Direct Assessment Program Manager	Manager, System Integrity	Ensure HCAs are assessed on time and following the process specified in RMP-09
Corrosion Engineer	Direct Assessment Program Manager	Performs all engineering related to the DA process. Reviews indirect assessment results, specifies locations for direct assessment, performs root cause evaluations, and performs post-assessment.

ILI Program Manager	Manager, Pipeline Engineering	Ensure HCAs are assessed on time and following the process specified in RMP-11.
Integrity Management Program Manager	Manager, System Integrity	Schedule Integrity Assessments, re-assessments and integrate data into GIS

5.10. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Develop ICDA procedure		Due 12/05
Develop CDA procedure		Due 12/06
Develop SCCDA procedure		Due 12/05

6. Remediation

6.1. Scope

Remediation is defined as action taken by the operator to mitigate the danger of a potential integrity concern. Remediation includes pressure reduction and/or repair and preventive measures that halt a potential integrity problem so it does not proceed to failure. This Section describes repair criteria that address issues identified by integrity assessment and data analysis. Preventive and mitigative measures are addressed in Section 9.

6.2. Background

192.933

The Company shall take prompt action to evaluate all discovered anomalies and remediate those that may threaten a pipeline's integrity.

The Company must be able to demonstrate that the remediation of a condition will ensure that the condition is unlikely to pose a threat to the long-term integrity of the pipeline until the next scheduled re-assessment.

If the Company is unable to respond within the prescribed time limits for any condition, operating pressure will be reduced or other measures taken to ensure the safety of the HCA. This reduction in pressure for an anomaly of concern cannot exceed 365 days unless the Company provides a technical justification that the continued pressure restriction will not jeopardize public safety or environmental protection. In addition, the OPS and CPUC must be notified.

All repairs must be per ASME B31.8 requirements.

6.3. Company Compliance

The Company's established repair procedures and schedules are specified in the procedures developed for the different inspection methods:

- ECDA – RMP-09
- ILI – RMP-11

6.4. Discovery of a Condition

192.933 (b)

Discovery of a condition is defined as that date when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator must obtain sufficient information about a condition no later than 180 days after an integrity assessment, unless the operator can demonstrate that the 180-day period is impractical.

For the following assessment techniques, "discovery of condition" occurs when:

- **ECDA** – the direct examination phase of the anomoly is completed.
- **ILI** – the Company receives documentation that there are anomalies meeting CFR 49, Part 192, Section O, Table 5.4.1 description of "Immediate repair conditions". This could occur in the preliminary and/or the final report from the ILI vendor.

material redacted

GTR0005760

6.5. Classification of Anomalies

Certain types of anomalies must be scheduled for repair and/or mitigation on a prioritized schedule, triggered by the dates of discovery. The prioritization shall include provisions for repair of the most dangerous defects in HCAs first, followed by the lesser anomalies, until all repairs and remediation activities have been completed. These classifications are detailed in RMP-09 and RMP-11.

6.6. Scheduling Remediation

Company shall prioritize the evaluation and remediation of conditions and set its repair schedule to remediate the most critical conditions first. All reports from integrity assessments shall be promptly reviewed and immediate repair conditions scheduled. Other conditions shall be reviewed within180 days and a response plan (repair schedule) developed.

The repair schedule shall include the methods and timing of the response.

The schedule for remediation follows the guidelines for repair conditions in B31.8S Section 7 unless special requirements apply. If Company cannot meet this schedule, Company shall:

- Justify the reasons why it cannot meet the schedule
- Demonstrate that the delay will not jeopardize public safety

If Company cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure, then the OPS and the CPUC must be notified per 192.949. See Section 15 Notification of Authorities for instructions on the notification process.

Additional Scheduling Considerations

Different responses in scheduling may be indicated depending on the type of integrity assessment conducted. B31.8S discusses these; they are listed in B31.8S table 3 and in Section 7.4 of this procedure.

6.7. Repair Methods

B31.8S Table 4 lists repair and prevention/detection methods that are acceptable for each of the nine threat categories.

Those repair methods typically used by Company include:

- Pipe replacement
- Sleeves and patches
- Composite sleeves
- Grinding
- Fill welds
- Direct deposition welding

6.8. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09	ECDA Procedure	Update as needed	RM File 7.9
RMP-11	ILI Procedure	Update as needed	RM File 7.11
UO Standard S4134	Selection of Steel Gas Pipeline Repair Methods	Intentionally left blank	Technical Information Library

6.9. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
See RMP-09 and RMP-11	See above

6.10. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
See RMP-09 and RMP-11	Not Applicable	Not Applicable

6.11. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Review this section	Integrity Management Program Manager	12/06

7. Continual Evaluation and Assessment

7.1. Scope

192.937

This Section outlines the schedules used for re-assessment, the periodic evaluation of HCA integrity according to criteria specified in the regulation, and the assessment methods.

7.2. Background

192.939

After the Baseline Assessment is complete, an operator must continue to assess all HCAs according to the intervals listed in 192.939 and periodically re-assess ensure continuing integrity.

Where prior assessments were used to meet BAP requirements, re-assessment must be performed no later than December 17, 2009.

All HCAs must be re-assessed by some method no later than seven years after the baseline assessment, or sooner if indicated by evaluation.

The presence of time-dependent modes of deterioration from some conditions makes repeated inspection imperative. Company has developed a process for continual integrity assessment and evaluation to maintain the integrity of HCAs. All activities performed in conjunction with Company's Integrity Management Program are an integral part of this cycle. These activities, modified and updated throughout each cycle, form a dynamic process with ongoing improvements.

Company will ensure that ongoing assessment intervals for HCAs do not exceed the seven-year requirement established in the rule. However, certain threats to specific pipeline operating conditions, such as external and internal corrosion may require a reduced examination and evaluation interval. If assessment results or other associated risk factors indicate the need, higher risk areas shall receive more frequent evaluation and an adjustment to the seven-year interval.

At the conclusion of each assessment, a Long Term Integrity Management Plan (LTIMP) shall be developed based on the integrated assessment information, remediation performed, pipeline information, and environmental information to establish reassessment intervals and prevention and mitigation plans. (Remediation will have been completed as part of the assessment activities in RMP-09 and RMP-11.) The LTIMP shall be documented and include data considered, how the data was integrated, analysis, and recommendations. Upon approval of the LTIMP by the Manager of System Integrity, the BAP, IMP, and IMACS shall be revised to reflect the updated plans. The LTIMP documentation shall be filed in the IMP.

Both the regulatory requirements for re-assessment schedules (such as the maximum re-assessment interval chart) and the engineering basis (remaining half-life calculations) must be considered when establishing re-assessment intervals. (See § 4.9) In addition, the following shall be considered when determining re-inspection intervals and in recommending prevention and mitigation measures:

1. Previous integrity assessment results (e.g. anomaly type and size, defect growth rate, etc.)

2. Data integration and risk assessment information as performed for the BAP and all subsequent re-assessments for the considered threat as well as for other threats
3. Pipe size, material, manufacturing information, coating type and condition, and seam type
4. Decisions about remediation, including leak and repair history
5. Product transported, including historical changes
6. Operating stress level (including potential for pressure cycle)
7. Existing or projected operation and maintenance activities, including additional preventive and mitigative activities
8. Any changes to the pipeline system design and operation, including any external changes that may have occurred since the last risk assessment
9. Local environmental factors that could affect the pipeline
10. Geotechnical hazards (earthquakes, landslides, erosion, etc.)
11. An analysis of all information and data about the integrity of the pipeline segment and the consequences of a failure
12. Scope of assessment (vs. intended scope)
13. Tool tolerance and Data Quality.
14. Consideration of providing prevention and mitigation measures to other pipeline segments (covered and uncovered) which have similar material and environmental characteristics.
15. Where preventive and mitigative measures have been deemed necessary, a schedule for implementing these measures shall be entered in IMACS. Where appropriate this schedule shall comply with Gas Standard O-16 and UO Standard S4134. Where similar segments operating in an area with similar environmental characteristics have been identified, a schedule shall also be established for their evaluation. Where active corrosion has been identified, schedules shall also be made for establishing preventive and mitigative measures.

In performing the review of assessments and establishing prevention and mitigation strategies, the following additional factors must be considered:

1. Potential for Third Party Damage (Dig-Ins, farming activity, noted as higher risk by field, foreign line crossings, USA information)
2. Inspection and Incident History (A and H Forms)
3. Cathodic Protection Records or CIS results.
4. Potential for Stray Current.
5. Risk Mitigation Strategies such as:
    a. Improving the cathodic protection,
    b. Implementing additional inspection and maintenance programs,
    c. Improving Line Marking,
    d. Additional landowner notification or public awareness efforts,
    e. Installation of Automatic Shut-off Valves or Remote Control Valves,
    f. Installation of computerized monitoring and leak detection systems,
    g. Replacing Pipe segments with pipe of heavier wall thickness, rerouting, or providing additional cover,
    h. Providing additional training to personnel on response procedures,
    i. Conducting drills with emergency responders.

A LTIMP Checklist (as shown Appendix F) or something similarwill be used to ensure that all of the appropriate data was considered, and referenced.

7.3. Ongoing Evaluation

Normal operation and maintenance activities, including field reporting, engineering, and facility mapping processes, constantly produce data in addition to inspection and mitigation activities. This data shall be analyzed and integrated in a continual process and should data indicate serious concerns that were not previously identified, the integrity assessment and mitigation activities will be revised. These continual changes to the physical and operating aspects of the pipeline must be managed through the Management of Change process, Section 12.8.

As stated in Section 2.3 and RMP-01 Section 6.5 risk analysis and threat identification will be reviewed annually. This review will identify if new high risk segments were created. If new high risk segments were created, the Integrity Management Plans will be revised and assessments re-scheduled appropriate with their risk and applicable threats.

7.4. Assessment Intervals

Re-assessment intervals are dependent upon the operating pressure at which the HCA operates, which type of assessment method was chosen for the Baseline Assessment and the actions taken as a result of the assessment. Table E.II.2 of Appendix E of the regulation and the Maximum Reassessment Interval chart from 192.939 of the regulation detail the maximum allowed re-assessment intervals. Table 3 of B31.8S also provides additional requirements in this area for Time-Dependent Threats.

Adjustments in the chosen assessment method and/or improvements to the risk assessment method(s) in use may become necessary as more complete and accurate information on the HCAs is accumulated. The specific threats and assessment techniques for each HCA is documented in the Integrity Management Plan its Integrity Management Area.

For pipelines operating below 30% SMYS, low stress assessments may be used every seven years in place of CDA.

192.939 Re-assessment Interval Chart

MAXIMUM REASSESSMENT INTERVAL

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment.	10 years (*)	15 years (*)	20 years.(**)
Confirmatory Direct Assessment	7 years	7 years	7 years.
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in § 192.941.

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.
(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

Table III B31.8S

Inspection Technique	Interval (Note 1)	>= 50% SMYS	30 - <50% SMYS	< 30% SMYS
Hydro test	5	TP to 1.25x MAOP (Note 2)	TP to 1.4x MAOP (Note 2)	TP to 1.7x MAOP (Note 2)
	10	TP to 1.39x MAOP (Note 2)	TP to 1.7x MAOP (Note 2)	TP to 2.2x MAOP (Note 2)
	15	Not Allowed	TP to 2.0x MAOP (Note 2)	TP to 2.8x MAOP (Note 2)
	20	Not Allowed	Not Allowed	TP to 3.3x MAOP(Note 2)
In-Line Inspection	5	PF > 1.25x MAOP (Note 3)	PF > 1.4x MAOP (Note 3)	PF > 1.7x MAOP (Note 3)
	10	PG > 1.39x MAOP (Note 3)	PF > 1.7x MAOP (Note 3)	PF > 2.2x MAOP (Note 3)
	15	Not Allowed	PF > 2.0x MAOP (Note 3)	PF > 2.8x MAOP (Note 3)
	20	Not Allowed	Not Allowed	PF > 3.3x MAOP (Note 3)
Direct Assessment	5	Sample of indications examined (Note 4)	Sample of indications examined(Note 4)	Sample of indications examined (Note 4)
	10	All indications Examined	Sample of indications examined (Note 4)	Sample of indications examined (Note 4)
	15	Not Allowed	All indications Examined	All indications Examined
	20	Not Allowed	Not Allowed	All indications Examined

Notes:

(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate reassessment of the interval.

(2) TP - Test Pressure

(3) PF - Predicted Failure Pressure as determined from ASME B31G or Equivalent

(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained with the process. These intervals provide for sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for re-inspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% SMYS

Table E.II.2 from Appendix E

Table E.II.2 Assessment Requirements for Transmission Pipelines in HCAs (Re-assessment intervals are maximum allowed)

Re-Assessment Requirements (see Note 3)

	At or above 50% SMYS		At or above 30% SMYS up to 50% SMYS		Below 30% SMYS	
Baseline Assessment Method (see Note 3)	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method	Max Re-Assessment Interval	Assessment Method
Pressure Testing	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	Pressure Test or ILI or DA				
		Repeat inspection cycle every 10 years	15 (see Note 1)	Pressure Test or ILI or DA (see Note 1)		
				Repeat inspection cycle every 15 years	20	Pressure Test or ILI or DA
						Repeat inspection cycle every 20 years
In-Line Inspection	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	ILI or DA or Pressure Test				
		Repeat inspection cycle every 10 years	15 (see Note 1)	ILI or DA or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	ILI or DA or Pressure Test
						Repeat inspection cycle every 20 years
Direct Assessment	7	CDA	7	CDA	Ongoing	Preventative & Mitigative (P&M) Measures (see Table E.II.3), (see Note 2)
	10	DA or ILI or Pressure Test				
		Repeat inspection cycle every 10 years	15 (see Note 1)	DA or ILI or Pressure Test (see Note 1)		
				Repeat inspection cycle every 15 years	20	DA or ILI or Pressure Test
						Repeat inspection cycle every 20 years

Note 1: Operator may choose to utilize CDA at year 14, then utilize ILI, Pressure Test, or DA at year 15 as allowed under ASME B31.8S
Note 2: Operator may choose to utilize CDA at year 7 and 14 in lieu of P&M
Note 3: Operator may utilize "other technology that an operator demonstrates can provide an equivalent understanding of the condition of line pipe"

7.5. Assessment Methods

Company used a detailed process for selecting the appropriate assessment tools. The procedures for selecting re-assessment methods are similar to those as described in Section 4 Baseline Assessment Plan with the addition of confirmatory direct assessment (CDA) and electronic surveys as assessment tools. CDA and electronic surveys can be used on an HCA when the scheduled re-assessment exceeds seven years and must comply with the conditions outlined in Section 8 Confirmatory Direct Assessment.

7.6. Using Low Stress Re-Assessments

192.941

This method can only be used for pipelines operating below 30% SMYS and must have had a baseline assessment per 192.919 and 192.921. The requirements for different threats are as follows:

External Corrosion Requirements

- Conduct an electric survey on cathodically protected pipe (i.e. indirect examination tool/method (procedure to be developed prior to performing to survey) at least every seven years on the HCA. The results of each survey shall be used as part of an overall evaluation of the cathodic protection and corrosion threat for the HCA and include, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.
- Assess unprotected pipe or cathodically protected pipe, where electrical surveys are impractical, with:
  - Leakage surveys as required by §192.706 at four-month intervals.
  - Areas of active corrosion shall be identified and remediated every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

Internal Corrosion Requirements

- Conduct a gas analysis for corrosive agents at least once each year
- Conduct testing of fluids removed from each storage field that may affect a HCA at least once each year

The data from these tests must be integrated at least every seven years with applicable internal corrosion leak records, incident reports, safety related condition reports, repair records, patrol records, exposed pipe reports, and test records. Then appropriate remediation actions shall be defined and implemented.

7.7. Deviation from Assessment Intervals

192.943

There may be situations when additional time is required to assess pipeline segments. Situations that could prolong assessment include:

- Internal inspection tools cannot be obtained within the required re-assessment period. Should this occur, Company must take whatever actions necessary to ensure the integrity of the segment during the interim.
- Product supply cannot be maintained if assessment is done within the required interval.

In these cases, Company will apply for a waiver from the OPS at least 180 days prior to the end of the required interval or as soon as product supply indicates the need for the waiver. A waiver application shall be filed in accordance with section 15.2 of this procedure. A copy shall also be submitted to the CPUC for their information.

7.8. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update	Location

		Schedule	
RMP-09	ECDA procedure	Update as needed	RM File 7.9
RMP-11	ILI procedure	Update as needed	RM File 7.11

7.9. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Integrity Management work management system (IMACS)	Work Mgmt software
CGT Standard S4110 Leak Survey and Repair of Gas Transmission and Distribution Facilities	Technical Information Library-online

7.10. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
See RMP-09 and RMP-11	**Not applicable**	**Not applicable**

7.11. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Not applicable		Not applicable

8. Confirmatory Direct Assessment

8.1. Scope
192.931

Integrity regulations allow an operator to use Confirmatory Direct Assessment (CDA) to meet the seven-year re-assessment requirement when the suggested re-assessment period for the baseline assessment method is longer than seven years.

8.2. Background
192.937 (c)(5)

Confirmatory Direct Assessment is an assessment method that can be used in limited circumstances for re-assessment. CDA follows the ECDA and ICDA plans with some exceptions.

8.3. Company Compliance

A procedure for CDA has not been developed at this time. By December 2006, a procedure will be developed to implement CDA as a re-assessment technique.

8.4. Allowable Uses

CDA may only be used for external corrosion and internal corrosion re-assessments.

8.5. External Corrosion Plan

CDA for external corrosion shall follow the ECDA Plan per 192.925 with the following exceptions:

- Use of only one indirect examination tool is allowed.
- All indications of immediate action must be excavated for each ECDA Region (refer to RMP-09 for a definition of ECDA Region).
- At least one high-risk indication meeting scheduled action criteria must be excavated in each ECDA Region.

8.6. Internal Corrosion Plan

CDA for internal corrosion shall follow the ICDA Plan per 192.927 with the following exception: only one excavation of high-risk location in each ICDA Region is required.

8.7. Scheduling and Repairs

If a defect revealed during CDA requires remediation prior to the next scheduled assessment, then the next assessment must be re-scheduled in accordance with the requirements of RP 0502 6.2 and 6.3.

If the defect requires immediate remediation, pressure must be reduced per 192.933 until the segment is re-assessed per 192.937.

8.8. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
CDA Procedure		12/06	To be developed.

8.9. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
To be developed (12/06)	Not applicable.

8.10. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
To be developed (12/06)	Not applicable.	Not applicable.

8.11. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Review as necessary.	Integrity Management Program Manager.	12/06

9. Preventive and Mitigative Measures

9.1. Scope

192.935

This section addresses additional preventive and mitigative measures that Company is taking to protect High Consequence Areas in accordance with 192.935.

9.2. Background

192.935

Section 192.935 requires the development of additional preventive and mitigative measures that address the following:

- Prevention of third party damage
- Prevention of outside force damage
- Automatic shut-off valves or remote control valves
- Low-pressure pipeline measures
- Also see section 7.2 for other necessary prevention and mitigation considerations.

9.3. Company Compliance

Table 4 B31.8S

The Company has established programs that address many of the suggested preventive and mitigative measures, both from 192.935 and those suggested in Table 4 of B31.8S.

Additional new measures shall be developed or existing measures refined as part of the Company's continuing evaluation and improvement program.

The following table summarizes the established processes and procedures included in Company's preventive and mitigative measures. More comprehensive descriptions of these programs/procedures follow the table.

Current Preventive and Mitigative Processes and Procedures

Prevention/ Detection Methods	Company Compliance Description	Procedure	Location
192.935			
Use of qualified personnel for marking, locating and supervision of excavations	OQ Qualified, Mark and Locate Annual Training,	Gas Info. Bulletin (GIB) 151, UO S4412, Protection of Underground Infrastructure Manual	Technical Information Library
Maintaining an excavation damage database (damage not limited to reportable incidents)	Incident report for every incident of known excavation damage and Risk Mgmt spreadsheet tracking root cause and relative likelihood of each incident		PG& E Risk Management Web Site
Monitoring of excavations	Stand-by all CGT facilities within 5 foot of any excavation	GIB 151 – Stand-By *2004 Safety Video-Excavation and Stand-By	Technical Information Library for GIB-151. and RM Library for video

Prevention/ Detection Methods	Company Compliance Description	Procedure	Location
First Responder Training and Preparation	Bi-Annual First Responder Program (FRP) *Pre Fire Plan Manuals for each Compressor Station	Bi-annual training with FR agencies who attend meeting. See FRP Web Site *Site map, and building layout for hazards and fire systems	District Offices & Compressor Stations *Front gate of each compressor station and a copy given to local fire Department during FRP meeting
Local Emergency Responder Drills	Annual Emergency District Drills	Simulate emergency situations at the compressor station or out on the pipeline. See Emergency Manual	District compressor station or field locations
Improved/Additional Inspections and Maintenance	Semi-annual leak survey for all Class 3 & 4 transmission lines not IMP assessed	Standard S4110	Technical Information Library
Automatic and Remote Valves	LTIMP Review	RMP-06	
Excavate or conduct above ground surveys in areas of unmonitored encroachments	Protect pipelines from encroachments and other unsafe activities near our facilities	SHC 104 – Observed Hazard Notification Third Party	Technical Information Library
Table 4: B31.8S			
Patrolling			
Aerial	Quarterly patrols with increased frequency during months with active agriculture	Standard S4111	Technical Information Library/local headquarters
Foot	Quarterly patrols with increased frequency during months with active agriculture	Standard S4111	Technical Information Library for standard/local headquarters for patrol records.
One Call Systems	Utilize California's Underground Service Alert for any excavations		
Public Education	Public Safety Information Program (PSIP) events concerning pipeline hazards and utilization of USA. Property owner notifications (PSIP) provide Pipeline safety information to the public and USA.	PSIP events recorded in Word for all events attended. GIS point is created to document all events with more than 100 attendees. Landowner notification program documented in hardcopy files and on server.	PG&E PSIP web site Sample landowner notification letter

material redacted GTR0005773

9.4. Risk Drivers for Establishing P&M Actions Section 5 B31.8S

Preventive and mitigative measures are based on the threats documented in Section 3 "Threat Identification" section of this procedure.

Risk Assessment methods in Section 5 of B31.8S, outlined in the Section 0 "Integrity Assessment", identify additional measures to protect HCAs. Following are the additional measures and their application within the Company's Integrity Management Program.

9.5. Preventing Third-Party Damage

Third party damage is consistently a major cause of pipeline releases. Information on the location of excavation damage that occurs in the transmission system should be maintained for both HCAs and non-HCAs. Additional P&M measures should be taken to address these incidents based on a root-cause analysis.

Company has take the following steps to help prevent third-party damage:

- Participation in Underground Service Alert (USA)
- Mandatory standby for any excavations within 5' of gas transmission facilities
- Landowner notification for portions of gas transmission facilities whose cover is less than required for a new installation (every two years)
- Landowner notification for all portions of gas transmission facilities with a history of 3rd Party damage or identified by operations personnel as vulnerable (every two years).
- Developed video documenting the process for locating, marking, stand-by and excavation around gas transmission facilities to educate our own personnel and contractor groups.
- Public presentations about 3rd party damage prevention.
- Additional pipeline markers

9.6. Outside Force Damage

All pipelines that are at risk from outside force damage, including earth movement, floods, and suspension bridge instability, shall receive additional preventive and mitigative attention. Some of these activities may include:

- Patrolling of vulnerable facilities after a seismic event...See Outside Force action plan
- Patrolling of vulnerable facilities after sufficient rain...See Outside Force action plan
- Maintaining a prioritized erosion database and GIS layer
- Replacement of pipeline with design more likely to survive event
- Relocation of the pipeline

9.7. Valves

Company follows a set of guidelines for all its pipelines concerning valve placement.

In-line Valves

Company may employ in-line valves on specific pipelines in sensitive areas to mitigate the effects of a possible release. The specific guidelines for utilizing in-line valves are being developed and the Integrity Management Program Manager is responsible for ensuring these guidelines are implemented prior to 12/31/06.

Automatic Shut-off and Remote Controlled Valves

As part of the LTIMP and in addition to normal valve replacement, Company shall consider the addition of automatic shut-off valves (ASV) or remote control valves (RCV) if they would be an efficient means of adding protection to an HCA. Additional specific guidelines for utilizing automatic shut-off valves are being developed and the Integrity

Management Program Manager is responsible for ensuring these guidelines are implemented prior to 12/31/06.

Maintenance and Operation of Valves

The Company shall follow CFR 49, Part 192, Subpart D, paragraphs 192.145 and 192.179 for the design and Subpart M, paragraph 192.745 for the maintenance of transmission line valves. The following Company procedures specify the details governing the Company's valve design and maintenance:

Valve Design:

Specification and Testing are in conformance with API Specification 6D, "Specification Pipeline Valves (Gate, Plug, Ball, and Check Valves)", (21st edition, 1994)
Related PG&E Standards
GS&S F-10, Valve Selection Requirements
GS&S F-21 Standard Ball Valve List: Carbon Steel 2" through 24"
GS&S F-21.1 Material Specification for Carbon Steel Ball Valves
GS&S F-31 Standard Carbon Steel Gate Valve List
GS&S F-40 Plug Valve - Codes and Data

Valve Maintenance:
Valve Maintenance is conduct in accordance with PG&E UO Standard S 4220, Valve Maintenance Requirements.

9.8. Minimizing Emergency Response Time

Operations personnel can receive information about pipeline leaks through pipeline system operations alarms, third-party observations, emergency response organizations, aerial patrols, and other means. Immediate response is imperative to any given situation involving an actual or suspected pipeline leak. Response procedures have been established for responding to pipeline emergencies. Those procedures will define an action plan that includes the following:

- A definition of organizational lines of responsibility and notification for response to unintended releases
- Training of all personnel responsible for responding to unintended release events
- Immediate verification of unintended releases, if necessary
- Isolation and control of the unintended release source

9.9. Low-Pressure Pipelines in Class Locations

192.935(d)
Table E.II.1 Appendix E
Table E.II.3 Appendix E

The Company has the following processes in place to address low-pressure that are non-HCA pipelines in Class 3 & 4 locations:

- Participation in California's one-call USA
- All excavations within 5 feet of gas transmission facilities are monitored throughout the excavation GIB 151.
- Semi-annual leak patrols will be required for all transmission pipelines in Class 3 & 4 that are not HCAs. This requirement was be added to Company Standard S4110 in 2005 and semi-annual leak patrols will begin in 2006.

9.10. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
Standby Requirements for Gas Transmission facilities GIB 151	See Title	As necessary	Technical Information Library
Leak Survey and Repair of Gas Transmission and Distribution Facilities S4110	See Title	As necessary	Technical Information Library
Patrolling Pipelines and Mains S4111	See Title	As necessary	Technical Information Library
Protection of Underground Infrastructure S4112	See Title	As necessary	Technical Information Library

9.11. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Outside Force Action Plan	RM File 8.4
Gas Emergency Response Plans	Technical Information Library
Semi-Annual Leak survey folders	District/Division Headquarters

9.12. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Corporate PSIP Manager	Safety Health and Claims	Corporate public communications and awareness training
CGT PSIP Manager	Manager of System Integrity	In charge of public communications and awareness training, and landowner notification
Manager System Integrity	Director of GSM&T	Responsible for all standards for maintenance and operation of gas transmission facilities

9.13. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Fully develop section 9. Document process for review of in-line and automatic shut off valve utilization	Integrity Management Program Manager	12/06

10. Performance Plan

10.1. Scope

192.945

This Section contains Company's Performance Plan, as required by 192.945, to determine that all integrity management program objectives are being accomplished and the integrity and safety of the pipelines are being effectively improved.

10.2. Background

B31.8S 9.4

A semi-annual evaluation of the elements of Company's Integrity Management Program must be made to ensure that the program is effective in assessing integrity and protecting high consequence areas. B31.8S 9.4 outlines four performance measures that must be included in addition to the specific measures for each threat as specified by B31.8S Appendix A.

Since External Corrosion Direct Assessment (ECDA) is used, this process must be per 192.925 (see Section 0 Integrity Assessment) and be monitored to ensure that the ECDA process is effectively assessing and mitigating risk. A semi-annual report to OPS and CPUC is due per 192.951 (see Subsection 10.4 and Section 15 Notification of Authorities).

10.3. Intra-system Measures

Company has developed a performance plan to perform intra-system comparisons and program measurements which address the following:

1. Overall program measurements including:
    - Number of miles of pipeline inspected compared to the program schedule
    - Number of immediate repairs completed
    - Number of scheduled repairs completed
    - Number of leaks, failures and incidents, classified by cause
2. ECDA effectiveness measures including:
    - Number of excavation performed each year (application of ECDA)
    - Number of Immediate repairs (results of the ECDA)
    - Number of Scheduled repairs (results of the ECDA)
    - Frequency of reprioritization (reliability/repeatability of ECDA)
    - Frequency of Immediate and Scheduled Indications
    - Number of leaks on pipelines with past ECDA surveys (absolute criteria)
3. All threat specific metrics for each of the nine threat categories
4. Risk algorithm validation including:
    - the number of incidents and risk values for the pipeline segments involved

The \\WalnutCrk01\CGT\ENG\LIBRARY\ANREPORT\IMP\200*X (where X is the digit of the current year. E.g. 2006)*\IMPmetrics*monthyear(e.g.metrics0605)*.xls spreadsheet documents these metrics and is used to provide OPS, INGAA and internal audiences with summaries of the Integrity Management Program's progress and effectiveness.

10.4. Performance Reporting

Regulatory Communications

Semi-annual reports shall be issued to OPS that include the four performance measures listed in Section 10.3 per B31.8S Section 9.4, which includes an ECDA Monitoring Report covering the measures as stated in 192.925. A semi-annual report must be submitted to the OPS and the CPUC per 192.945, beginning August 31, 2004. Subsequent semi-annual reports shall cover the period through June 30 and December 31 of each year and are due within two months of the cutoff date. The reports must be complete through June 30 and December 31 of each year and must be submitted by two months after those dates. The report submitted in August should include data for the first half of the calendar year. The report submitted in February should include data covering the entire calendar year (i.e., updating the information in the August report).

Internal Communications

Company shall use a monthly report to communicate the progress and effectiveness of the Integrity Management Program. The monthly report shall be distributed to California Gas Transmission's Vice President, and shall document the work planned and completed during the year (progress. In addition the semi-annual reports to the OPS and the CPUC shall be distributed to the VP of CGT and the Director of GSM&TS to communicate the progress and effectiveness of the System Integrity Program.

10.5. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
RMP-09 ECDA Procedure	ECDA Process	As needed	
RMP-11 ILI Procedure	ILI Process and data gathering	As needed	

10.6. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Risk Mgmt Annual Report to CPUC	Risk Mgmt Library

10.7. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	. Manager of System Integrity	Select performance indicators for reports, Compile and submit performance reports
. Compliance Engineer	Manager of System Integrity.	Internal Audits

ILI Program Manager	Manager of Pipeline Engineering.	Provide ILI data for performance reports
DA Program Manager	Manager of System Integrity	Provide ECDA data for performance reports

10.8. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Performance Reports to OPS, CPUC and VP CGT	Semi-annual through June 30 and December 31 of each year (due by August 31, and February 28 of each year)	February 28/29 and August 31 of each year
Monthly status reports to VP CGT	Monthly updates to management by the 15th of the following month	Each Month

11. Record Keeping

11.1. Scope

This Section covers the records and supporting documentation that are part of Company's Integrity Management Program.

11.2. Background

192.947

All records and other documentation that demonstrate compliance with the requirements of the integrity management regulations must be kept for the useful life of a pipeline. Section 192.947 lists the records, at a minimum, which must be available for review during an inspection.

11.3. Company Compliance

At minimum, these records shall include documentation which addresses the following:

- Written integrity management program
- Threat identification and risk assessment
- Baseline assessment plan
- Decisions, analyses, developed processes used to implement and evaluate each element of the baseline assessment plan and integrity management program
- Personnel qualification and training
- Schedule prioritizing conditions found during any process of the integrity management program
- Actions taken to comply with direct assessment requirements
- Actions taken to comply with confirmatory direct assessment requirements
- Integrity Management Plan for each IMA including the long term integrity management section detailing any mitigation or prevention activities initiated by the assessment and documentation for the re-assessment schedule (see Section 7.2).
- All required documentation and notifications to OPS, state authorities with which OPS has an interstate agreement, and the CPUC.

These elements often consist of more than one source of documentation and/or records. The section for each element describes any required documentation, supporting reports, etc.

11.4. Roles and Responsibility

Responsibilities for ensuring compliance for record keeping are covered in the applicable section for each element of the integrity management regulation and are summarized in the Company Integrity Management Calendar for each section.

11.5. Calendar

Dates for compliance, including any record keeping requirements, are detailed in the applicable section for each element of the integrity management regulation.

Action Item	Reviews & Updates	Next Scheduled Date
Intentionally left blank		

12. Management of Change

12.1. Scope

Company has several ways to track changes in pipeline systems, procedural documentation and training. These existing methods are included in this section, along with procedures and forms used for Management of Change (MOC) for the Integrity Management Program.

12.2. Background

Management of change procedures are required to identify changes to pipeline systems and consider the impact of those changes on the integrity of the pipeline. Both major and minor changes, whether temporary or permanent, shall be documented, including:

- Technical
- Physical
- Procedural

12.3. Company Compliance

Company has an overall Management of Change Procedure to ensure that changes to programs are made for good reason with Company approval. The procedure outlines how changes are made, who makes the changes, and how those changes are passed on to individuals and organizations within the Company.

Processes that Company follows to ensure changes that could potentially affect the integrity of a pipeline are tracked and transmitted are described below and throughout this procedure. Company uses standard MOC forms in addition to the other documentation and procedures as described throughout this procedure. These forms are:

- **Integrity Management Program Change Form**: This form documents the changes and technical justification for all revisions to Risk Management Procedures (RMP's) (Appendix D)
- **IM Procedure Exception Request**: This form is used to document infrequent or "one-time" variances from the procedures described in this manual.
- **Testing Schedule or Tool Change Management Form:** Used to approve any changes in the assessment-testing schedule or tool selection.
- **Integrity Management Plan Change Form**: Documents decision process and changes to the individual Integrity Management Plans (Appendix E).
- **MAOP/MOP control form (part of UO standard DS0430/S4125):** Used to document and control changes in MAOP and MOP.

Integrity Management Procedure Change Process

At least once each year, changes to RMP 6 will be reviewed and approved by the Vice President of CGT/President and CEO of Stanpac. Interim changes to RMP 6 as well as changes to all other RMP's will be reviewed and approved by the Manager of System Integrity.

The objective for the integrity change management process is to ensure that qualified personnel are involved in the analysis, documentation, and approval of changes to the IMP. This process ensures:

- Appropriate reviews and approval are obtained prior to making a change to the program.
- Approved changes are documented in a timely manner.
- Changes to the program are communicated to the organization in a timely and accurate manner.

The integrity change management process governs both major and minor documentation changes to the Integrity Management Program. Any employee can request changes to the program.

Changes to this procedure shall be communicated to all affected team members and training will be conducted as soon as practicable to ensure that work is performed to the latest requirements of the procedure. The communication should normally be done within 5 days of approval and training should be completed as soon as practicable.

The Integrity Management Change process requires any person with a change request to RMP-06 to submit the request to the Integrity Management Program Manager. If the change request is generated from the ECDA Program Manager, the ILI Program Manager or a member of the Integrity Management team, then the Integrity Management Program Manager can review the text changes directly.

For example, if the PSI Program Manager has changes to the Prevention and Mitigation section RMP 6 this procedure, the changes should be submitted directly to the Integrity Management Program Manager. If the change request is generated from another source, then the Integrity Management Program Manager will review the proposed changes with the respective specialist. The final changes to the text will receive the concurrence of the technical specialist and be approved by the Integrity Management Program Manager and others as shown above.

12.4. Communication of Changes

Communication of all changes to Company system processes and procedures shall follow the guidelines as presented in Company's Communication Plan (see Section 14).

12.5. Use of Record of Change Form

The Integrity Management Program Change Form is used to track changes and updates to this procedure (Appendix D).It will accompany each RMP being routed for signatures as part of the approval process.

12.6. Results/ Documentation

Records for Management of Change associated with Company's Integrity Management Program will be maintained in the following location:

- GIS archives
- Risk Management (RM) files
- All changes to Risk Management procedures will be highlighted in the new version and all versions will be reviewed by the Integrity Management Program Manager and approved by the Manager of System Integrity. The current version of procedure will be stored on the intranet and all versions will be stored in the Integrity Management library.
- Changes to the schedules for integrity assessments will be documented in the individual Integrity Management Plans. These changes, including the reason for the change, will be approved by the Integrity Management Program Manager. If a pipeline's assessment is moved from the "first five years" to the "second five years", the change will be further approved by the Manager of System Integrity and approval noted with a "letter to file". The documentation will be saved in the pipeline's Integrity Management Plan. Finally, IMACS will be updated with all schedule changes to ensure proper tracking of proposed assessments.
- Changes to Company Standards and Specifications will be made and documented through the existing MOC process for these documents.

12.7. Technical Changes

As integrity assessments are completed, changes to operations for the system may possibly be needed, e.g. improved cathodic protection. These changes may flow both from the system operations to the Integrity Management Program and, as a result of determinations made by integrity management processes, from the Integrity Management Program back to the system. These technical changes will be noted in the "Long Term Integrity Management Plan" section of each pipeline's Integrity Management Plan (IMP).

As new technologies are developed, some of these are likely to be incorporated into IMP processes and procedures. These shall be communicated to appropriate staff and procedures for any new technology documented. See the Procedural Changes subsection for more information about this process, including training requirements.

12.8. Physical Changes

Physical changes occur throughout the lifetime of a pipeline and may include the inclusion of newly identified HCA segments. Company tracks these changes by patrols, maintenance and repair procedures, one-call activity reports and construction "as-builts".

These changes are documented as follows:

- During pipeline patrols or during normal maintenance, Standard Practice 4127 requires new construction to be identified and communicated to the Mapping department for incorporation into GIS. This notification is made on Appendix C of Standard Practice 4127 and a copy is to be sent to the Integrity Management Team for new HCA review. The Integrity Management team will document the results of each review in a note in the Mapping Department's New Construction Reports File.
- Whenever new construction or repairs are made to a pipeline, or any physical changes are made or observed, these changes are communicated via job as-builts or pipeline inspection reports and include a red-lined drawing, GPS coordinates and/or a sketch of the location. The applicable information from these reports is then entered into CGT's GIS. This review process will include changes to operation diagrams.

  Construction "as-builts" are posted to GIS as they are received by the Mapping department. Annually, the Integrity Mgmt Team will review GIS for all pipelines that have been newly constructed or relocated. These are easily identified by the "Date_Created", "Yr_Install" fields and the absence of a value in the "HCA_ID" field.

- Leak reports (CGT Standard S4110) are updated in GIS either as they occur or during the semi-annual review for the IM Program metrics and OPS annual report. Leaks from backbone transmission lines are sent directly to GSM&TS Mapping and are entered when they are received. Leaks on local transmission lines that are maintained by Division personnel are entered when the information is gathered for the IM Program metrics or OPS annual report.

  All GIS changes made to the following pipeline properties: Route, Trans_Def, Segment_No, MP1, MP2, MOP, OD, W_THICK, JntEff, SMYS, Long_Seam, Yr_Install, Test_Date, Test_Pressure, QA, COAT_TYPE, Asmt_Plan, Class_Present, HCA_ID, (these are column headings to the attribute table in the pipeline layer of GIS) and new records are noted in the Audit_Reportchanges Table on the SQL Server.

  Each change noted in the Audit_Reportchanges Table shall be evaluated by a Risk Management Engineer for potential impact on the Integrity Management Program. Impacts can include, but are not limited to:

  a. The creation or elimination of HCAs caused by changes to the PIR (caused by changes in OD or MOP) or pipeline alignment (caused by improved positional accuracy or a re-route),
  b. An increase in risk caused by changes in stress, test records, or other pipeline properties, (See RMP 01, RMP-02, RMP-03, RMP-04, and RMP-05 for a complete list of attributes that may affect risk) and
  c. A change in applicable threats caused by changes in stress or other pipeline properties such as Joint Efficiency Factor, Longitudinal Seam type, Year Installed, or coating type. (See Section 3 of this RMP for a complete list.)
  d. Potentially create a change in the Transmission Definition (see Appendix A) due to service to a large volume customer. As new pipelines are identified in the Audit Change Table, the review shall include consideration of whether the pipeline is being added to serve a large volume customer. If so, the review will ensure that the transmission definition and HCA identification will be applied appropriately..

Where pipeline changes impact integrity management plans for existing HCAs or produce new HCAs, revisions shall be made to the BAP and the applicable Integrity Management Plans. The IMP Change Status Log shall also be updated to ensure all the applicable data files are changed and the implication for the change is evaluated. GIS and IMACS shall also be updated to reflect changes to the BAP and Integrity Management Plans.

The Risk Management Engineer shall note acceptance of the pipeline change in the Audit_Reportchanges Table by adding his or her initials in the 'review_by' column and the date of his or her review in the 'review_date' column. Supplementary Notes regarding impact of the change on the Integrity Management Program should be included in the Audit_Reportchanges Spreadsheet to explain the basis of acceptance. GIS changes should be evaluated within three months of posting in GIS. In no case shall the evaluation extend beyond one year. **No changes shall be accepted in the Audit_Reportchanges Table prior to Integrity Management Plans being revised and submitted for approval unless the change in GIS was to add a newly installed pipe segment and the necessary revision to the integrity management plan has been entered in the IMP Change Status Log.** An IMP Change sheet as shown in Appendix E should be routed with the Integrity Management Plan during the approval process and filed in the IMP change binders when approved.

- One-Call activity reports are entered into GIS using the centroid of the "area of interest" noted by the One Call operators. This data can be used:
  - Identify clusters of One Call activity
  - Integrate with ECDA or ILI data to identify potential 3rd Party damage

- Changes to MOP are managed through Standard Practice S4125:

HCA Identification Change Process

Company has the responsibility of incorporating newly identified HCAs into its Integrity Management Program within one year of identification. At the current time, Company will review changed parcel/land use information, new or changed pipelines, and field/First Responder reports to identify new or changes to existing HCAs. The field/First Responder reports and pipeline changes will be reviewed quarterly and the parcel/land use information will be reviewed annually.

See Section 17 New HCA Identification for more details.

12.9. Procedural Changes

Existing Management of Change to Company's standard operating procedures is handled by the following:

- Operations Manual
- Standards process

Currently, Company communicates changes and updates to procedures as they are available.

Revisions are published, unless the change is a compliance issue, as with IM Program. Those updates and changes are sent out to the divisions and other personnel immediately.

12.10. Change Communication

There are four different groups that need to be informed of changes that occur depending upon the type and significance of the change. These groups are:

- Integrity Management personnel
- Other Company personnel
- Office of Pipeline Safety (OPS)
- California Public Utilities Commission – Safety Branch (CPUC)

Integrity Management Personnel – Whenever any changes occur to RMP-06, formal training will be documented for the affected Integrity Management Team, Direct Assessment Team and the In-Line Inspection Team, members.

Other Company personnel – Whenever any changes occur affecting the patrolling requirements or data collection requirements for field personnel or contractors, a standup meeting shall be held to review the changes.

Office of Pipeline Safety – Within 30 days of making a change that substantially affects the program's implementation or significant change to the program or schedule, the Company shall notify OPS of the change, the reason for the change and any actions taken to ensure the safety of the public is not compromised. Examples of significant changes include the following:

- Merger of Companies or major acquisition of a transmission pipeline system,
- Determination of susceptibility to SCC when previously considered unsusceptible,
- Introduction of an assessment methodology not previously used,
- Abandoning an assessment methodology previously planned for use.

In addition, when changing a high risk pipeline's scheduled assessment from "the first five years" to "the second five years", the Company will notify OPS of the change, the reason for the change and any actions taken to ensure the safety of the public is not compromised.

Notifications must provide enough information for OPS to understand the reason for deviation/change from the actions specified in the program. When a specific pipe segment is affected, the notification must also include information about the affected pipe segment and HCA. Notifications must also include the name, title, telephone number, and e-mail address of the Manager of System Integrity, who may be contacted if additional information is needed.

California Public Utilities Commission – Notification to the California Public Utilities Commission shall be submitted as shown for the Office of Pipeline Safety. In addition, the Company will provide an annual report that will document progress and includes the current version of the current Risk Management Procedures.

Additional information concerning notification to regulatory officials can be found in Section 14 (Communication Plan) and Section 15 (Notification to Authorities).

12.11. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
Not applicable			

12.12. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Integrity Management Program Change Form	Appendix D
IM Program Exception Request Form – to be developed by Integrity Management Program Manager by 12/05	Intentionally left blank
Testing Schedule or Tool Selection Change Form – to be developed by Integrity Management Program Manager by 12/05	Intentionally left blank
IMP Change Status log	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis\2004 Final Systemwide\IMP CHANGE STATUS.xls
Audit Report Change Log	\\Walnutcrk01\Mapping\RiskMgmt\Integrity Managment Plans\Threat Analysis\2004 Final Systemwide\Audit_ReportChanges.xls
Integrity Management Plan Change Form	Appendix E

12.13. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Vice President of CGT/President and CEO of StanPac	Executive Vice President of Utility Operations	Annually approves RMP-06
Manager of System Integrity	Director of GSM & TS	Reviews and approves all RMP changes.
GSM&TS Mapping Supervisor	Operations Support Manager	Ensure timely updates of GIS with construction as-builts, pipeline inspection reports, leak reports, new construction reports and MAOP changes
Integrity Management Program Manager	Manager – System Integrity	Updating and communicating changes to RMP 01, 02, 03, 04, 05 and 06. Responsible for authorizing and documenting changes to assessment schedules and ensuring communication to proper authorities.
Direct Assessment Program Manager	Manager – System	Updating and communicating changes to RMP-

	Integrity	09. Seek authorization for changes to Direct Assessment schedules and obtain authorization from Integrity Management Program Manager. Training of and annual review with Direct Assessment team about RMP-06 and RMP-09.
In-Line Inspection Program Manager	Manager – Pipeline Engineering	Updating and communicating changes to RMP-11. Seek authorization for changes to In-Line inspection schedules and obtain authorization from Integrity Management Program Manager. Training of and annual review with In-Line Inspection team about RMP-06 and RMP-11

13. Quality Assurance

13.1. Scope

192.911
B31.8S

The regulation points to B31.8S for guidance when creating a Quality Assurance (QA) plan. According to Section 12 of B31.8S, quality control is defined as "documented proof that the operator meets all the requirements of their integrity management program." This Section describes Company QA measures to verify the implementation and effectiveness of the IM Program.

13.2. Background

B31.8S 12.1
B31.8S 12.2

B31.8S Section 12 says that pipeline operators with an existing quality control program that meets or exceeds the following requirements can incorporate the integrity management program activities within their existing plan.

"(a) Requirements of a quality control program include documentation, implementation and maintenance. Six activities are usually required:

(1) Identify the processes that will be included in the quality program.

(2) Determine the sequence and interaction of these processes.

(3) Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective.

(4) Provide the resources and information necessary to support the operation and monitoring of these processes.

(5) Monitor, measure, and analyze these processes.

(6) Implement actions necessary to achieve planned results and continued improvement of these processes.

(b) Specifically, activities that should be included in the quality control program are as follows:

(1) Determine the documentation required and include it in the quality assurance program. These documents shall be controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include risk assessments, the integrity management plan, integrity management reports and data documents. (See Procedures and sections.)

(2) The responsibilities and authorities under this program shall be clearly and formally defined. (See Roles and Responsibility section.)

(3) Results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvement.

(4) The people involved in the integrity management program shall be competent, aware of the program and all of its activities and shall be properly trained to execute the activities within the program. Documentation of such competence, awareness and qualification, and the processes for their achievement, shall be part of the quality control plan.

(5) The operator shall determine how to monitor the integrity management program to show that it is being implemented according to plan and document these steps. These control points, criteria and/or performance metrics shall be defined.

(6) Periodic internal audits of the integrity management program and its quality plan are recommended. An independent third-party review of the entire program may also be useful.

(7) Corrective actions to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored."

13.3. Company Compliance

Company uses quality assurance checks to confirm that the program addresses pipeline system integrity issues. Such quality assurance includes periodic analysis of data to promote continual performance improvement and regular monitoring of the Program's implementation.

The data analysis includes an annual review of pipeline incidents and once each calendar year SME steering committees meet to discuss recommended changes to existing Risk Mgmt Algorithms.
Program compliance is monitored by monthly reporting of assessments completed compared to the assessments planned in the Baseline Assessment plan, and audits of Integrity Management Program processes and procedures, held at least once each calendar year.

The specifics are detailed in the following sub-sections.

13.4. Performance

Performance tracking provides objective evidence for evaluating integrity activities and the program effectiveness. Such measures may be used in addition to those required for reporting to OPS. (See the Performance Plan section for more information.) These help present the status of integrity goals in an objective manner and enable the Company's upper management to be aware of non-compliance with the mileage commitments in the Baseline Assessment Plan.

On a monthly basis, the Integrity Mgmt Program Mgr collects the miles of assessments completed through Phase 2 and reports to the Vice President of CGT/CEO of Stanpac.

13.5. Preventive Measures

Company monitors surveillance and preventive activities, and these indicate how well Company is implementing the various integrity management elements. The required semi-annual surveys are scheduled in PG&E's Work Management software and these records are reviewed during PG&E's internal regulatory compliance audits.

13.6. Incident Measures

Incident measures determine if goals for fewer incidents and less threat to people and the environment are being met. These are documented in CGT's Incident reports and the annual statistics are summarized by the PSIP Manager and reported in the CPUC Integrity Risk Mgmt Annual report.

13.7. Data Verification

All data used in risk assessment shall be verified and checked for accuracy on a periodic basis. A qualified individual within Company or an outside expert shall do verification of data. RMP-01 explains the sources and methods of ascertaining data for risk assessment.

13.8. Internal/ External Audits

Either an Internal or anexternal audit will be performed each calendar year to ensure compliance with our own procedures and to ensure those procedures meet regulatory requirements.

Internal Audits

There is no requirement for an internal audit during the calendar year if there is an external audit in that calendar year. .

External Audits

Periodically, Company shall undertake an external audit by a qualified industry source. The external audit will examine IM Program performance against regulatory requirements and other companies. This audit will measure how the Company's Integrity Management Program and activities are progressing in relation to the regulation and other companies in the industry.

13.9. Corrective Action

If the Company Integrity Management Program is found through this Quality Assurance process to be lacking in any aspect, changes to the Integrity Management Program shall be implemented according to the Management of Change process. Such changes shall be documented according MOC rules, and the effectiveness of those changes shall be monitored via the Quality Assurance process.

13.10. Qualified Company Personnel

Company personnel involved in the Integrity Management Program shall be fluent in the program and its activities, and properly trained to execute those activities.

Company has existing procedures to document the qualifications of its personnel, which are detailed in the qualifications and training section of each procedure.

The specific personnel that Company must have to carry out an Integrity Management Program are outlined in the Roles and Responsibility sections in each element of this Plan.

13.11. Contractor Qualification

B31.8S 12.2

The DA procedures and ILI procedures shall specify the process utilized to verify contractors' qualifications to perform the work. Generally, these are specified in the Contract Specifications for each job.

13.12. Results Distribution

After Integrity Management Program reviews and audits, the results will be reported to the CGT – VP, GSM&TS –Director, the managers of System Integrity and Pipeline Engineering, and the program managers for ILI, Direct Assessment and Integrity Management.

13.13. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
ILI Program Manager	Pipeline Eng. Mgr	Monthly reporting of assessments and metrics
DA Program Manager	System Int. Mgr	Monthly reporting of assessments and metrics
Int. Mgmt. Program Manager	System Int. Mgr	Monthly reporting of assessments completed, Risk calculation reviews, SME Steering

		Committee meetings, CPUC Risk Mgmt report, Scheduling audits
Public Safety Info. Prog (PSIP) Mgr	System Int. Mgr	Incident metrics

13.14. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Review of Pipeline Incidents	Annually reported to CPUC	4/06
Internal or External Audit	Every calendar year	12/06
SME Steering Committee Meetings	Every calendar year	12/06
Monthly reporting of assessments completed	Monthly	
Validation of Risk Calculations	New system wide risk calculations	4/06

14. Communication Plan

14.1. Scope

This section contains all cross-communication among parties involved in integrity management and operations.

14.2. Background

192.911
B31.8S 1

The regulation states that a communication plan must include the elements of B31.8S Section 10, and procedures for addressing safety concerns raised by:
(1) OPS; and
(2) A State or local pipeline safety authority when a HCA is located in a State where OPS has an interstate agent agreement.

14.3. Company Compliance

B31.8S 10 and 10.1

This Company communications plan is intended to keep appropriate Company personnel, jurisdictional authorities and the public informed about the Company's Integrity Management Program. The information may be communicated as part of other required communications.

Communications shall be conducted as often as necessary to ensure that appropriate individuals and authorities have current information about the operator's system and their integrity management efforts. Communications shall take place periodically and as often as necessary to communicate significant changes to the integrity management plan.

Some of the information is communicated routinely. Other information may be communicated upon request.

14.4. External Communication

B31.8S 10.2 and 10.3

Information will be communicated to the following groups of people outside of the Company. (The Company does not necessarily limit its external communications to these groups):

1. Landowners and tenants along the rights-of-way
2. Public officials other than Emergency Responders
3. Local and regional Emergency Responders
4. General public
5. Regulatory Agencies

The following describes the types of communication processes that have been established for each of the above groups.

Landowners and tenants along the rights-of-way. Prior to performing integrity assessments (DA, smart pigging, etc.), as part of the integrity assessment process, all the landowners and tenants inside the designated High Consequence Area will be notified. Most of these notifications will occur and be documented in the job files by letter. One on one communications will occur while gathering data in the field, and any and all questions will be addressed. Additional notifications will occur if direct examinations are required that could in any way disrupt normal landowner activities. See Section 9.5 for additional notifications.

Public Officials other than Emergency Responders. Prior to performing integrity assessments (DA, smart pigging, etc.) all permitting agencies, including all applicable city, county, and federal agencies, will be notified as to the objectives and details of the specific assessments to be performed. Any and all concerns will be addressed. Documentation for this communication will be part of the permit package, and any additional correspondence will be included in the job file.

Local and regional Emergency Responders. As part of the Company's Public Safety Information Program (PSIP), biennially each operations and maintenance District holds an informational "open house" meeting with all first responding emergency agencies. These meetings are documented via the PSIP program documentation process. Integrity Management activities will be fully communicated and discussed at these meetings and the Emergency Responders will be queried about HCAs near Company pipelines.

General Public. Any concerns or questions raised by the general public will be promptly addressed.

Regulatory Agencies. As required by 49 CFR part 192 Subpart O, the Company will submit semi-annual performance metrics to both DOT/OPS and to the CPUC. Additionally, the Company will continue to submit annual Risk Management/Integrity Management Reports to the CPUC, that document all the related Risk and Integrity Management activities the Company has accomplished during the course of the previous year.

14.5. Crisis Communication

The Company (GSM&TS) Emergency Plan Manual contains specific communication procedures and requirements in the event of a crisis. Crisis would include natural disasters affecting public safety or supply, security threats, deaths or accidents, or any other event that could adversely impact the Company's ability to provide safe and reliable natural gas transmission service, such that it would immediately impact the public or the environment. All key stakeholder contact information, including employees, agencies, corporate security, first responding agencies, etc. are listed in these procedures. Procedures for communication with the media are included in these procedures.

Company standard 4413 provides specific requirements for what incidences require regulatory or agency reporting, who to report to, and the required reporting timeframes. This standard fully complies with 49 CFR Part 192 requirements and includes telephonic reports to the CPUC, Gas Quarterly reports and Safety Related Condition reports. During integrity assessments the Company will ensure this standard is followed to ensure proper reporting of any serious conditions or incidents that may occur.

14.6. Internal Communication

The Company will regularly communicate the status and results of the gas transmission Integrity Management activities. Each calendar year, the Vice President, California Gas Transmission (CGT) will author and distribute a general compliance email to the CGT organization, which will summarize the general results and activities associated with the Integrity Management Program.

Regular communication at all levels will occur during the year. Email, tailboards, and meetings will provide the mechanisms for the bulk of this communication. The intent is for every CGT employee to be aware of and understand the basics of the Integrity Management initiative. .

A Company wide web site is maintained within PG&E's intranet system to promote Pipeline Integrity and Risk Management related information exchange. The Integrity Management Program Manager is responsible for posting the mission /vision and related informational updates, such as system wide risk statistics and mitigation efforts, a summary of the incidents occurring on the pipelines and the current CPUC RM Annual Report.

When employees in the field discover potential hazards, employees can use the web site to notify the Risk/Integrity Management team of the concern via the on-line "Pipeline Risk Evaluation Form. If immediate action is required, the Integrity Management Program Manager will champion the necessary immediate action.

14.7. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
RMP-9 ECDA Procedure (Landowner Notification)	RM Files
RMP-11 ILI Procedure (Landowner Notification)	RM Files
Company Gas Emergency Plan	Technical Information Library
Pipeline Safety Manual	RM Files
First Responder Manual	RM Files
S4413 CPUC and DOT Reportable Incidents	Technical Information Library

14.8. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Manager, System Integrity	Director, GSM&TS	Overall Integrity Management Program Compliance
Integrity Management Program Manger	Manager, System Integrity	Integrity Management Program Manager
Direct Assessment Program Manager	Manager, System Integrity	Direct Assessment Program
ILI Program Manager	Manager, Pipeline Engineering	IL Program

14.9. Calendar

The following dates address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
VP Authorization of RMP-06	Each calendar year	10/2005
CPUC/DOT Risk/Integrity Management Report	Annually	4/2006
VP IMP internal communication to org. about IMP	Each calendar year	1/2006
PSIP Communications to First Responders	Biennially	Varies by District
Metric Reporting to OPS and CPUC	Semi-Annually (02 & 08)	2/28/06
Integrity Management Program Communications	Semi-Annually	
Integrity Management Performance Metrics (Internal)	Monthly	
Update Company Integrity Management Website	Each calendar year	
Update General Public Communications Form	As needed	
Distribute General Public Communications Form	As needed	

15. Notification of Authorities

15.1. Scope

Notification of authorities is required at various times during the integrity management process. Company may also be requested to submit the risk analysis or integrity management program. This Section presents the details and procedures for those notifications.

15.2. Company Compliance

Company makes notifications and reports to OPS and the California Public Utilities as part of it the implementation of the integrity management regulations. These include:

- Submittal of risk analysis or integrity management program
- Use of other technology as an assessment method
- Significant deviation or change from assessment schedule or program (see section 12.10)
- Inability to meet remediation schedule and to temporarily reduce operating pressure
- Semi-annual performance metrics

Where the Company believes it must deviate from the assessment intervals as called for in section 192.943, a waiver shall be sought from the Secretary of Transportation in accordance with 49 USC 60118(c). That section of the code allows the Secretary to waive compliance with this requirement on terms the Secretary considers appropriate, if the waiver is not inconsistent with pipeline safety. The Secretary shall state the reasons for granting a waiver and may act on a waiver only after notice of an opportunity for a hearing. Copies of any waiver requests to the Secretary should also be sent to the CPUC for their information.

15.3. Processes for Compliance

OPS Notifications

The table below lists the acceptable methods of communications with OPS. Company's general policy is to use on-line notification.

Type of Communication:	Method:	Contact Information
Notifications:	**Mail:**	Information Resources Manager Office of Pipeline Safety Research and Special Programs Administration U.S. Department of Transportation Room 7128 400 Seventh Street, SW Washington, DC 20590
	Facsimile	Information Resources Manager (202) 366–7128
	Online:	Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/gasimp*
Reports:	**Mail:**	Information Resources Manager Office of Pipeline Safety Research and Special Programs Administration U.S. Department of Transportation Room 7128 400 Seventh Street, SW Washington, DC 20590
	Facsimile	(202) 366–7128
	Online Reporting System:	OPS Home Page at http://ops.dot.gov

State Authority Notifications

California is the only state in which the Company has pipelines. The Company's general policy is to use mail to notify the state authority.

STATE OF:	**California**	
AUTHORITY:	**Public Utilities Commission – Safety and Reliability Branch**	
Type of Communication:	**Method:**	**Contact Information**
Notifications:	**Mail:**	[redacted]
	Facsimile	
	Online:	[redacted]
Reports:	**Mail:**	
	Facsimile	
	Online Reporting System:	

15.4. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	System Integrity Manager	Semi-annual report, CPUC Annual Risk Management Reoprt of any significant changes to the Integrity Management Program.

16. Environmental and Safety Measures

16.1. Scope

This section of the Integrity Management Program covers environmental and safety risks, and the steps taken by Company to ensure that the baseline assessment is being conducted in a manner that minimizes those risks.

16.2. Background

Currently, OPS has not issued any specific guidelines for minimizing environmental and safety risks. However, the Company has in place an extensive safety program. In addition, procedures are being developed to address excavation issues of transmission pipelines and the Company has a number of environmental procedures in place to address spills and cleanup in an environmentally safe manner. The purpose of these procedures is to guide employees in taking the proper action to contain and clean up a spill of any environmentally sensitive material to mitigate environmental damage and to ensure compliance with applicable local, state, and federal requirements.

A summary of these procedures follows and relevant documentation is included in the subsections16.6 Procedures and 16.7 Supporting Documents.

16.3. Company Compliance

192.919 (e)

Company has the following procedures in place to ensure that measures are taken to minimize environmental and safety risks during baseline assessment. Water and wastes are assessed prior to disposal to determine the appropriate method based on Local, State, and Federal regulations, as well as Company policy. Once the assessment is completed which may include analytical testing, proper disposal is arranged through a contracted waste disposal contractor. Additionally, permits for disposal of wastes and waste water discharge maybe required prior to any action.

GSM&TS's EHS uses a checklist which identifies applicable Environmental Health and Safety (EHS) regulations and Company policies which is reviewed and completed prior to the onset of any project. This checklist identifies areas in which EHS assistance maybe necessary either prior to, during, or at the completion of the project. The Company Environmental Affairs Department has a Cultural Resources and Protected Species Program. This program includes the identification and location of species and their habitat. Training is given for the GSM&TS field employees on an annual basis for Endangered Species and Habitat Awareness and biennial for VELB and Tortoise training.

16.4. Industry Input

Permit Times Conflict with Repair Deadlines

The potential for compliance problems arises when an anomaly scheduled for repair according to the regulation is located in an area with endangered species, an archeological site, or other cause for delay to excavation and repair. Under such circumstances, Company could potentially have difficulty meeting the regulation timelines.

Company should develop an assessment of local, state and federal permits required for IMP projects in each division. The assessment will include an inventory of all permits, identification of the associated permitting agencies, and identification of provisions that would conflict with IMP implementation requirements.

- Participate in pre-planning efforts that expedite permitting. Locally, Company can contact the agencies that issue permits and keep lines of communication open prior to developing a baseline assessment schedule. If there is difficulty in establishing contacts with permitting agencies, Company can work with OPS CATS members to establish those contacts.
- Give priority to processing of permits for immediate or time-sensitive repairs.
- Hold general educational meetings with DOT, industry, federal, state and local agencies in the area through which Company transmission line runs to talk about IMP prior to scheduling any assessments or repairs. Explain the rule and industry issues, and learn agency issues. Ask permitting agencies for their input on how the industry should proceed. Document all meeting for audit purposes.
- Hold pre-project planning meetings and permitting meetings with agencies involved to ask for their help.
- Maintain constant communication with permitting agencies before, during and after projects.
- Project upcoming issues to eliminate rush requests.

Environmental High Consequence Areas and Safety Policies

Company shall utilize existing Cultural Resource Inventories, Protected Species Inventories, and planning maps for the distribution areas within each division and along the corridor of all IMP transmission lines. A complete list of these resources will be developed by the Integrity Management Program Manager and available by 12/06

Cultural Resources and Critical Habitat are required to be protected by state and federal agencies. Assessment of these resources is required as a prerequisite for some state actions and for all federal actions and probably any general permit that may be issued for the IM Program. Assessment of these resources on an individual project basis could require time delays that would be inconsistent with the expectations of the IM Program.

Once guidance documents help determine what permits might be needed for a particular site, projects can then be scheduled according to the permits needed, in anticipation of time delays.

CGT's safety policies are identified in the CGT Safety and Health Management System Plan, 2005, and the Company Code of Safe Practices. Our Plan includes various safety and health processes and programs which meet and maintain our compliance with the regulations. Additionally there are Company-wide processes which act as an umbrella for our safety and health programs. GSM&TS works with Hazmat on a local basis through each District/Facility Area or project. The EHS Field Specialists work with the Environmental Monitors present at each District to manage and dispose of hazardous wastes.

The Districts have Hazardous Materials Business Plans (HMBP) which identify our handling , managing and disposal of hazardous wastes. Phone numbers of local Hazmat and other Emergency Response EHS related events are also kept in the HMBP at the facilities and or the District offices. The EHS Field Specialists and the Environmental Monitors also have this information readily accessible.

The EHS Field Specialist is the contact with the County emergency response agencies (CUPA's), the State and EPA. The EHS Field Specialist communicates information to the emergency community via telephone and then by a follow-up written report if required. The information is further communicated back via the EHS Field Specialist to the specific supervisor of the facility or District. Upper management is also in the communication loop via the supervisor. The Law Department is also notified by phone call and a follow-up written report.

The environmental, safety and health procedures/processes have matured for many years and are continually being revised and updated to reflect the changing regulations and Company policies.

General Industry Cal/OSHA Safety Orders are monitored by the EHS quarterly field assessments, through biannual Company/Union safety walkarounds, by annual Safety and Health Corporate Self-Audits and by weekly observations through our behavior based safety program (GASPROS).

Environmental regulations are monitored through quarterly field assessments and by internal periodic audits. Contractors may be used to conduct these audits.

Updating of Company EHS procedures is done based on a regular frequency. Training for EHS programs are conducted through regularly scheduled District safety meetings on a quarterly basis.

16.5. Processes for Compliance

16.6. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

Title	Description	Update Schedule	Location
To be developed			

16.7. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
Cultural resource, Protected Species inventories for GIS	To be determined
To be developed	

16.8. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
To be developed		

16.9. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Fully develop section 16	Integrity Management Program Manager	12/06

17. New HCA Identification

17.1. Scope

This section covers processes for newly identified High Consequence Areas.

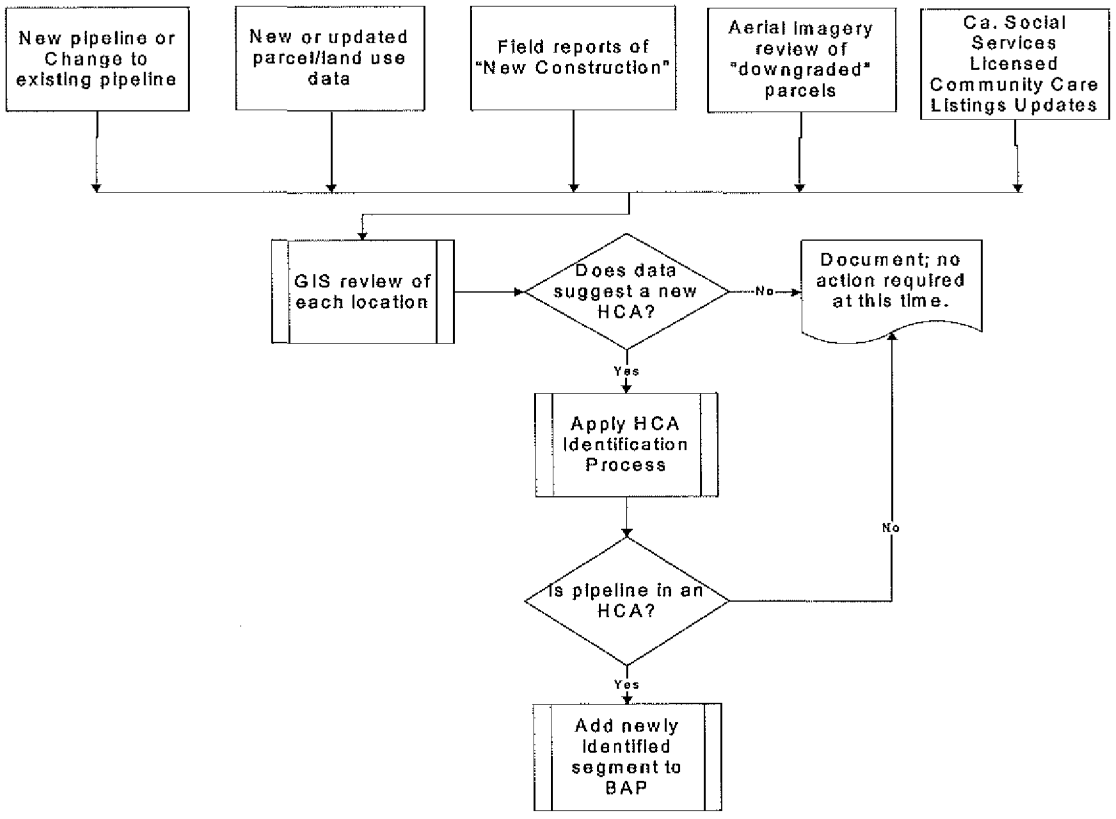
17.2. Background

There are nine causes for a newly identified High Consequence Area:

1. New installation or changes to an existing pipeline
2. New or updated parcel/land use information
3. Data that suggests an HCA under development (Field "New Construction" reports)
4. Updated aerial imagery
5. Surveys to verify identified sites (Field Engineer Reports)
6. Public Official Notification
7. Surveys to verify identified sites (Field Engineer Reports)
8. Information from first responders and public officials
9. New licensed community care facility

The New HCA Identification flowchart shows the high-level process for new HCA identification.

New HCA Identification Process



17.3. Company Compliance

192.905

192.921

Newly identified High Consequence Areas go through the same integrity management processes as all other HCAs. They must be incorporated into the Company baseline assessment plan within one year of discovery, and assessment must be completed within 10 years of identification.

Information about possible new HCA areas comes from different sources. Some of these may include (but are not limited to):

- Routine patrolling
- New construction drawings and reports
- New parcel data
- Updated land use designations
- New information from Ca. Social Services Licensed Community Care Listing
- Procedure to update class locations
- Surveys to verify identified sites (Field Engineer Reports)
- Aerial imagery review of parcels whose structure count or identified site designation was downgraded because historical aerial photography revealed the structures were out of the impact zone
- Information from first responders and public officials such as the California Social Services Licensed Community Care listing

17.4. New Pipeline and Changes in Existing Pipeline

New pipelines or changes in existing pipeline operating conditions could create HCAs. The following data shall be reviewed to identify these changes:

- Annually a GIS review will be performed to assess all pipeline segments newly installed or reconstructed
- Annually review GIS for pipelines with pressure tests in the previous year. This review will verify that existing processes have notified the Integrity Management team of all pipeline operating changes
- As they occur, all MAOP/MOP changes shall be reviewed. The Integrity Management team is cc'd on all changes.

The process detailed in paragraph 1.3 will be followed to determine if the new pipeline route or impact zone creates an HCA. All newly identified HCAs will be added to existing or a new Integrity Management Plan and scheduled for assessment within 10 years of the HCA identification.

17.5. Data Suggesting a New HCA

The following data will be reviewed (as specified) to determine if new HCAs exist:

- Annually review all parcels whose land use codes have changed
- Annually review the most current aerial photography for all parcels with downgraded "Structures" or "Id Sites" to determine if new structures or expansions to existing structures have changed the parcel's designation
- Annually review Ca. Social Services Community Care Listing
- Annually review all "Notice of New Construction" from the previous year to capture any "Identified Sites" discovered by field personnel.
- Biennially review input from First Responders
- Every 5 calendar years do a complete review of transmission pipelines to re-verify HCA identification (using the latest aerial imagery).

17.6. Procedures

This subsection contains a list of the procedures and/or other documentation used to comply with this element of the integrity management regulations.

	Description	Update	Location

		Schedule	
RMP-08	Identification, Location and Documentation of High Consequence Areas (HCA's)	As necessary.	RM Files

17.7. Supporting Documents

The following documents/references are incorporated as part of Company's Integrity Management Program.

Title	Location
RMP-08	RM Files
Land Use Codes for Counties	RM File 15
PG&E Parcel Data Feature Class Descriptions from Cadastra	RM File 15

17.8. Roles and Responsibility

Specific responsibilities for ensuring compliance with the element covered by this Section are as follows:

Title	Reports to:	Responsibilities
Integrity Management Program Manager	Manager of System Integrity	Ensure all HCA reviews occur
PSIP Manager	Manager of System Integrity	Gathering First Responder input
Integrity Management Program Manager	Manager of System Integrity	Obtaining the licensed community care listing from California Social Services

17.9. Calendar

The following outlines dates that address compliance requirements for this element.

Action Item	Reviews & Updates	Next Scheduled Date
Land use code review	Annually	12/2005
Review parcels with land use code change	Annually	12/2005
Ca. Social Services Licensed Comm. Care Listing	Annually	10/2005
New Pipeline Construction	Ongoing	Ongoing
Changed Pipeline Operating Conditions	Ongoing	Ongoing
Notice of New Construction	Ongoing	Ongoing
First Responder input	Biennially	As meetings occur
MAOP/MOP changes	As they occur	As they occur
Complete HCA Identification Review	Every Fifth Year	12/2009

Record of Change Log

Version [xx]			
Date	Location (Physical location in IMP manual)	Action (Minor Change, Process Change, Update, Clarification, etc.)	Description (fix typo, change of responsibilities, etc.)

Appendix A. Transmission Line Definition

CODE INTERPRETATION

Subject 49CFR Section 192.3 Definitions….Transmission Lines

Problem In order to consistently respond to the annual DOT and FERC data requests and to evaluate CGT pipeline maintenance and operation compliance with DOT Pipeline Safety Regulations (49CFR192), GSM&TS needs to determine which of its pipelines should be classified as transmission and which should be classified as distribution.

Code Language

Transmission Line means a pipeline, other than a gathering line, that:

(a) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;
(b) Operates at a hoop stress of 20 percent or more of SMYS; or,
(c) 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.

OPS Code Interpretations

Transmission Line:

11/30/78 – "Since the term 'transmission line' was used in those notices and the notices were, in general, based on the U.S.A.S. B31.8 Code (1968 ed.), we agree that the notices must have been drafted with the B31.8 definition of 'transmission line' in mind…..Since the term 'transmission line' in Part 192 is intended to have the same meaning as that in the B31.8 Code…."

08/09/88 – "A pipeline, a piece of which is operated at 20 percent or more of SMYS, is classified as a transmission line at least to the terminus of the last segment operating at 20 percent or more of SMYS.

05/30/91 – "(ends at)..the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale."

Distribution Center:

Per OPS interpretations on 11/30/78 and 5/30/91 a distribution center is:
"..the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale."

PG&E application of the definitions/interpretations

In addition to the OPS code interpretations; GSM&TS must document the following internal definitions in order to document the classifications of the pipelines it operates:

Maximum Operating Stress (MOP):

The lowest MAOP in a pipeline segment is considered by PG&E to be the MOP. The MOP is used to calculate the hoop stresses in a pipeline segment and determine the percent of SMYS for each unique pipe section in the segment.

Numbered Lines and DFMs:

Historically GSM&TS' pipelines have been segregated into two classifications; Numbered Transmission Lines, and DFMs. These classifications reflected the ASME B31.8 function of the pipelines and the FERC accounting used to construct them. Numbered Transmission lines were considered transmission, and DFMs were considered functionally distribution. DFMs operating over 20% SMYS were accounted as distribution but maintained as transmission to meet the CFR 49 definition.

Distribution Center:

CGT will consider the distribution centers to be "points" where gas flows into non-transmission DFMs (operating under 20% and primarily delivering to customers who have purchased it for consumption), or district regulating stations that feed distribution mains and services. 1

Large Volume Customer:

CGT defines large volume customer as a customer whose usage qualifies as a noncore end-use customer according to Tariff schedule G-NT. To qualify, a customer must: 1) have an average historical use through a single meter of greater than 3,000,000 therms/yr for the previous three years and a historical use of greater than 2,500,000 therms/yr in the most recent 12-month period or be able to document an increase in gas use due to permanent changes in the operations of the Customer's facility that will cause usage to exceed 3,000,000 therms/year.

Interpretation

Unless a review determines that the definitions have been incorrectly applied, the following criteria will be used to determine if a pipeline will be classified as transmission. Misapplications of the criteria will be documented at the end of this interpretation. The criteria are as follows:

a) Transports gas...
    - Pipelines historically numbered and classified as transmission to meet CFR 49 reporting and maintenance requirements.
    - All pipelines directly connected to gas gathering lines
    - Pipelines primarily used to deliver gas to customers who purchase it for resale as opposed to customers who purchase it for consumption.
    - All pipelines, not downstream of a distribution center, whose primary customer is a large non-core customer, even though it may be operating below 20% SMYS.

b) Operates at or above 20%...
    - All portions of pipelines that operate with a hoop stress at or above 20% SMYS or precede a portion that operates with a hoop stress at or above 20% SMYS.

c) All pipelines transporting gas within or from a gas storage field

Misapplication of PG&E's transmission line interpretation

A review was performed system-wide to determine if there were pipelines that had been incorrectly defined as DFMs or as numbered transmission lines. The interpretation was used to determine the correct classification. PG&E's GIS was updated to reflect the correct classification, but the pipeline number was not changed so that the link to historical documentation would not be lost. To date these misapplications are limited to: 119D, 126A, 126C, 126D, 137A, 137C and 137D.

Appendix B. Typical Pipe Data Element

Note: A description of each of the fields and the codes used shall be documented in the annual Systemwide Threat Analysis Key. (As an example for the 2004 five bay area counties, the key is contained in <u>\\Walnutcrk01\Mapping\RiskMgmt\Integrity Management Plans\Threat Analysis\2004 Systemwide Risk Calc Values2 5 County.xls</u>

PIPE and ENVIRONMENT DATA

IMA# 002_0.00

Route 002

Source Route   Source MP 0

Segment	142.5	MP1	76.19	MP2	76.46	Footage	1425

PIPE DATA							
Yr Installed	1/1/1969	OD	26	Pipe Mat	X60	Trans Def	T
Age	35.85	MOP	890	WT	0.322	SMYS	60000
Seam	DSAW	Jef	1.000	%SMYS	59.89%	Class	1
Girth Weld	A	Girth Jnt	BUTT	Mech Coupling?		PIR	535
Pipe Manuf.							
PT Date	1/1/1969	PT Media	W	PT Dur	0	PT Pressure	1480
PT Age	35.85	Wrinkle Bend		Mech Cplg?		Strength	1486
Cond		DM Leaks		Product	NG	LDM	0
External Corrosion Considerations							
Type	HAA	Installed	1/1/1969	GIS Cond	F	Aform Cond	
ILI		CIS		ECDA		Yr of EC Leak	
AC/DC Int	M	Casing		Soil Res	0	LEC	32.9
Internal Corrosion Specific Considerations							
IIC Threat Identified?		None					
SCC Specific Considerations							
Distance from nearest Compressor?	>20	SCC Incidents?	No	Stress > 60% SMYS?	No	Coating	HAA
Third Party Considerations							
Cover (GIS)	5	Cover (A-F)	0	Dig-In Mag		TP Leaks	
Line Mark		P Protect	S	Public Ed		LTP	14.2
Ground Movement Considerations							
Grnd Accel (X100)	40	Crossing		Erosion		Unstable Soil	
GM Mitigation						LGM	0
Consequence Considerations							
RR		Highway		HCA		Crit Facility	
Airport		Envir Area		HCA ID	I5		
Gas Load	-9	# Cust Out	-9	FSF	1	Wtr Xing	
IOE	0	IOR	18	IOP	16.71	COF	15.55
RISK Values							
LEC	32.9	LTP	14.2	LGM	0	LDM	0
LIC		LOF	14.62	IM COF	1.30	IM RISK	18.96
Past Assessment		I01					

Appendix C. Typical Threat Analysis Sheet

THREAT ANALYSIS

IMA# 002_0.00

Route 002

Segment	142.5	MP1	76.19	MP2	76.46	Footage	1425
1.0 External Corrosion Threat							
Type	HAA	Installed	1/1/1969	GIS Cond	F	Atom Cond	
ILI		CIS		ECDA		Yr of EC Leak	
AC/DC Int	M	Casing		Soil Res	0	LEC	32.9
Pipe Age	35.85	Coating Age	35.85	Does the EC Threat EXIST?		Yes	
2.0 Internal Corrosion Threat							
		IC Threat Identified?	None	Is a IC Threat KNOWN?		No	
3.0 SCC Threat							
Stress > 60% SMYS?	No	Distance to Compressor Less than 20 Miles?	No	SCC Incidents?	No	Coating Type other than FBE?	Yes
Compressor Station				Does SCC Threat EXIST?		No	
4.0 Manufacturing Threat							
Cast Iron	No	Pipe Age >50 Years	No	Mechanical Coupling?	No	Acetylene Girth Welds	No
Low Temps?		Land Movement?	No	Jef < 1.0?	No	Seam	DSAW
TP/MOP	1.66			Low Freq. ERW or Flash Welds?	No	LDM	0
Notes				Does the Manufacturing Threat EXIST?		No	
5 Construction Threat							
Wrinkle Bends?		Pre-1947 Pipe?	No	Mechanical Coupling?	No	Girth Welds	A
Low Temp?		Land Movement	No	Gmd Accel (X100)	40	Unstable Soil?	
Notes:				Does the Construction Threat EXIST?		No	
6 Equipment Threat							
Covered by separate process							
7 Third Party Damage Threat							
Dig-In Magnet		Cover	5	Public Ed		P Protect	S
Third Party Incidents		LTP	14.2	Does the Third Party Threat EXIST?		Yes	
8 Incorrect Operations Threat							
Notes:				Does the Incorrect Operations Threat EXIST?		Yes	
9 Weather and Outside Force Threat							
Gmd Accel (X100)	40	Crossing		Erosion		Unstable Soil	
GM Migation?		LGM	0	Does the Weather/Outside Force Threat EXIST?		Yes	
10 Hard Spot Threat							
% SMYS	69.89%	Installed	1/1/1969	Seam Type		DSAW	
Pipe Manuf.							
Hard Spots?		CP Level		Does the HS Threat EXIST?		No	

Appendix D. RMP Change Form

Pacific Gas and Electric

Integrity Management Program Change Form

Changes for RMP- ______

Revision ________ Date____________

Standard Pacific Pipelines Inc.

Attachment D to RMP-06

Page 97 of 101

Section	Change	Reason for Change	Implication of Change

Appendix E.

IMP CHANGE SHEET

IMP:			REV:		
Date Entered					
Route:			Segment:		
Made By:		Approved By:		Date:	
Change:					
Detail Change Description					
Reason for Change					

Doc	File	Status
BAP		
BAP Data	BAP-PGE-REV01.xls	
BAP Change Sheet	BAP-PGE-REV01.xls	
Threat Analysis Spreadsheet	BAPRev01 Threat Analysis.xls	
IMP		
IMP Changed	(Hardcopy)	
Approved		
GIS		
Pipe Spec		
HCARisk		
IMAC		*
Assessment Team Notification		

Notes:	
Implication Analysis	

material redacted

GTR0005814

Appendix F. LTIMP Checklist

Appendix F LTIMP Checklist

Category	Item	Checklist	Status	Notes
Data Gathering and Integration	A.1	Integrity Management Plan for the IMA pulled from files and available for review with GIS data.		
	A.2	A and H Form Themes are visible during review		
	A.3	All past assessments identified, integrated in GIS, legendized appropriately, and visible for review while panning results (In Notes provide themes and location of themes)		
	A.4	Remediations are incorporated into GIS		
	A.5	Studies/Reports available on the section of pipe are available for consideration during review (In Notes Provide References) (Ensure that root cause reports are considered.)		
	A.6	Pipe Properties theme visible and legendized based on HCA_ID		
	A.7	Risk Theme loaded and available for consideration during panning		
	A.7.a	Theme of Pipelines identified by field as having a higher level of risk from third party damage loaded and visible (mag_loc)		
	A.7.b	Foreign Line Themes loaded and visible (In Notes provide themes used)		
	A.7.c	Geotechnical hazards loaded and fault theme, landslide, and erosion themes visible. (Other themes shall be made visible as appropriate.)		
	A.7.d	Electric Transmission Lines Theme loaded and Visible		
	A.7.e	Raillines Theme Loaded and Visible		
	A.8	USA Information loaded and available for consideration during panning		
	A.9	Aerial Photography is available and utilized during review.		

Appendix F LTIMP Checklist

Category	Item	Checklist	Status	Notes
	A.10	Parcel Data Loaded and available for review to verify extent of HCA's		
	A.11	PIC Tool Results loaded and available for review to verify extent of HCA's		
Review / Analysis / Recommendations	B.1	Verify that the assessment covers the intended scope of assessment using appropriate tool. (Refer to GIS)		
	B.2	If ILI, check for Internal Corrosion damage reported. If damage reported and verified (ascertain if it exists), ensure that the route and segment are included in the IMP/BAP/IMACS/ and Threat Spreadsheets as an Internal Corrosion Threat. If applicable, scope out extent of threat application.		
	B.3	If ECDA, check for identification of Internal Corrosion threat/damage, SCC damage, and selective seam weld damage. If damage reported, ensure that the route and segment are included in the IMP/BAP/IMACS/ and Threat Spreadsheets as an Internal Corrosion Threat. If applicable, scope out extent of threat application.		
	B.4	Using GIS, pan through integrated data, analyze, and establish desired prevention and mitigation measures. In addition to the data integrated and reviewed in Items A.1 to A.14, ensure that the following risk mitigation strategies are considered:		
	B.4.a	While panning, review HCA to ensure that it looks appropriate.		
	B.4.b	Improved cathodic protection – Recoat, addition or alteration of rectifiers, anodeflex, etc.		
	B.4.c	Improved resistance to Third Party damage (Improved Line Marking, Landowner Notification, additional public awareness efforts, increased cover, thicker pipe, relocation)		
	B.4.d	Implementing additional inspection and maintenance programs.		
	B.4.e	Installation of Automatic Shut-off Valves or Remote Control Valves		
	B.4.f	Installation of computerized monitoring and leak detection systems		
	B.4.g	Providing additional training to personnel on response procedures		

Appendix F LTIMP Checklist

Category	Item	Checklist	Status	Notes
	B.4.h	Conducting drills with emergency responders		
Determine Reassessment Schedule	C.1	Calculation of reassessment interval based on data integration as shown in A.1 to A.14		
	C.2	Calculation of reassessment interval based on risk		
	C.3	Calculation of reassessment interval based on threats		
	C.4	Calculation of reassessment interval based on § 4.9 of RMP-06		
	C.4.a	ILI -		
	C.4.b	ECDA -		
Documentation	D.1	Description of process completed and incorporated into IMP		
	D.2	Description of recommendations for preventive and mitigative measures. Rank priority of measures based on risk.		
	D.3	Description of recommended additional investigation.		
	D.4	IMP Revised and Approved by Manager of System Integrity		
	D.5	Update of IMACS to track that preventive/mitigative and investigative efforts are completed and completed as risk indicates. (Pipelines that have been identified as similar and requiring preventative and mitigative measures shall also be entered into IMACS.)		
	D.6	BAP / GIS / IMACS / and Threat Spreadsheet revised to reflect next assessment plan.		
	D7	Consideration to Prevention and Mitigative measures to pipeline segments that may have similar material and environmental characteristics.		