TAB 11

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
ACTIONS TO PROMOTE SAFETY ON PG&E'S GAS TRANSMISSION SYSTEM, AND ON LINE 132 SPECIFICALLY

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This chapter responds to Directives 3 and 4 of the OII. Directive 3 asks PG&E to "[p]rovide a summary of actions PG&E took between 1955 and September 8, 2010 to promote safety with respect to its natural gas transmission pipelines in general and San Bruno's line 132 in particular." While Directives 3.A-3.C and 3.E call on PG&E to explain its system-wide actions to promote safety, parts of Directive 3 (particularly Directive 3.D) focus on PG&E's actions with respect to Line 132. Directive 4 asks PG&E to list, identify and describe the types of historical documents and other information the Company has used to make safety risk assessments on its transmission lines between 1990 and 2010.

The response to Directives 3 and 4 is organized into four Chapters. Chapter 6A responds to Directives 3.A-3.C, summarizing the actions PG&E took to promote safety with respect to the construction, design and initial testing of its transmissions lines. Where industry or regulatory standards, or PG&E's practices, changed over time, PG&E explains those changes to give context. In many instances, PG&E has drawn upon older records, including past safety-related reports to Commission staff, to explain its past gas safety practices.

Chapter 6B also responds to Directives 3.A-3.C, and provides a similar overview of the actions PG&E took to promote safety with respect to the operations and maintenance of its gas transmission system. Like Chapter 6A, this chapter frames the discussion around the regulatory context. It describes ongoing maintenance and operations activities and provides an historical perspective of past actions and programs to promote safety within PG&E's gas transmission operations and maintenance.

Chapter 6C addresses two closely linked directives, both related to system-wide written safety risk assessments of transmission pipe: Directives 3.E and 4. In Directive 3.E, the Commission directs: "Provide all written safety risk assessments that PG&E conducted between 1955 and August 2010 on any and all transmission pipes in its system during that time." In Directive 4, the Commission further directs PG&E as follows: "Between 1990 and 2010, in conducting safety risk assessments on its transmission lines, for purposes of deciding whether to replace portions of the line, list and identify, and describe, the types of historical documents and other information that PG&E used to make its assessments (e.g. as built documents, operational pressures)."

Chapter 6C provides a narrative response to these directives, including a discussion of how PG&E's pipeline safety risk assessment practices developed over time. It then refers the Commission to written safety risk assessments that are being provided as part of this submission, and, for the period from 1990-2010, lists, identifies and describes the kinds of historical documents that were used to make the written safety risk assessments.

Finally, Section 6D responds to Directive 3 (and specifically 3.D) as it relates to Line 132 and explains the actions that PG&E has taken on Line 132 to promote safety from 1955 to 2010. Because these directives (Directives 3 & 3.D) focus on actions taken on a particular transmission line, as opposed to system-wide or programmatic actions, PG&E's response is more granular. It explains in detail discrete actions to promote safety on Line 132 over the past 55 years and includes written safety risk assessments relating specifically to that line. In many instances, the explanation draws upon historical pipeline records.

The scope of activities that promote safety, and thus that respond to Directive 3, is not well defined in the OII. To assure a comprehensive response, PG&E has attempted in each of these chapters to link categories of activities described in the directives to Subparts of Part 192 of the federal regulations. Thus, for example, when explaining its historic operations practices, PG&E has organized its response around the main categories of activities described in subpart L of Part 192 (Operations). Likewise, when explaining its historic maintenance practices, PG&E has organized its response around the main categories of maintenance activities described in subpart M (Maintenance). The point is not to suggest that PG&E takes only those safety actions described in Part 192, but rather to provide a structure around which to organize this response.

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6A
PG&E'S DESIGN, CONSTRUCTION, AND INITIAL TESTING PRACTICES AND PROCEDURES TO PROMOTE SAFETY

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CHAPTER 6A
PG&E'S DESIGN, CONSTRUCTION, AND INITIAL TESTING PRACTICES AND PROCEDURES TO PROMOTE SAFETY

A. PG&E Has Designed, Constructed, and Initially Tested its Transmission Pipelines Pursuant to Company Standards and Practices Written to Promote Safety and Fulfill State and Federal Requirements

This Chapter responds to Directives 3.A-3.C of the OII, describing the actions PG&E took within the areas of design, construction and initial testing to promote the safety of its gas transmission pipelines between 1955 and 2010. The Chapter focuses on PG&E's safety-related standards and practices corresponding to the pertinent federal regulations found in 49 C.F.R. § 192 subparts A (General), B (Materials), C (Pipe Design), D (Design of Pipeline Components), E (Welding of Steel in Pipelines), G (General Construction Requirements for Transmission Lines and Mains), I (Corrosion Control), and J (Testing).

To respond to the OII's directives, this Chapter provides a historical perspective as well as a description of PG&E's current standards and practices. The discussion is divided into two time periods: before and after state pipeline regulations took effect in 1961. Written company procedures may pre-date and/or exceed regulatory requirements. As noted in Chapter 1A, a significant part of PG&E's gas transmission pipeline system was constructed before state regulation of gas pipelines took effect in 1961 (and a majority of it was installed before the enactment of federal regulations in 1970). During the time period before state regulation, PG&E undertook to promote safety by conforming construction practices and specifications to industry standards. Since 1961, PG&E's design, construction, and testing practices have been shaped by state, and later federal, safety rules.

1. Pre-1961 Design, Construction, and Testing Practices Undertaken to Promote Safety

It is difficult to recount details about pipeline design and construction practices more than 55 years after the fact. In this section, PG&E examines a selection of large pipeline projects undertaken in the 1950s about which the most is known. These projects provide a window into how PG&E designed and constructed pipeline in an era before pipeline safety regulations.

Faced with significant population growth and limited in-state natural gas reserves, PG&E began exploring construction of connecting pipelines (that today form PG&E's backbone transmission lines) to out-of-state suppliers in the late 1940s. PG&E's first connection to such a supplier came about in 1948 when PG&E applied for a Certificate of Public Convenience and Necessity to link its transmission network to gas-producing fields in New Mexico, Colorado, Utah, and Texas. This project involved constructing over 500 miles of pipeline between Topock and PG&E's Milpitas Terminal, with a delivery capability of 400 million cubic feet of natural gas per day. (P3-00001). The project was ambitious, calling for use of the largest pipe ever used in a gas transmission line to date – 34-inch main referred to as the "Super Inch" fabricated at the Consolidated Western Steel Corporation plant in South San Francisco. (P3-00002). The line had to cross the rugged terrain of the Mojave Desert and Tehachapi Mountains. Contractors from Bechtel Corporation, Conyes Construction Company, and the H.C. Price Company completed installation of the line (now known as Line 300A) and three supporting compressor stations in Topock, Hinkley, and Kettleman by the end of 1951.

PG&E designed the Topock-Milpitas line with safety considerations, ratepayer interest, and pipeline capacity in mind. One way of harmonizing these interests was by "tapering" the wall thickness of particular sections of pipe. (P3-00003). Tapering took advantage of the natural change in the pressure gradient along the pipeline to allow the utility to install thick-walled pipe in areas designed to operate at high pressure, and thinner-walled pipeline in sections designed to operate at lower pressures due to their distance from compressor stations. The determining factor for establishing a change in the wall thickness of the pipe was the maximum allowable operating pressure (MAOP) of a particular section of the line. MAOP was determined by using a safety factor that was consistent with the class location of the section of pipeline. The class location was determined based on the population density along the pipeline. The MAOP of the pipeline was that which did not exceed the allowable percentage of specified minimum yield stress for its class location. Pressure limiting stations were installed upstream of reduced wall thickness sections to ensure that the MAOP of the pipeline would not be exceeded under line packing conditions (increasing the quantity of gas in the pipeline during off-peak periods to satisfy forecasted peak demands).

Over the next several years, PG&E filed supplemental applications to increase the capacity and reliability of the Topock-Milpitas line by installing parallel runs of pipe. (P3-00004). In 1955, PG&E filed one of these supplemental applications to install additional sections of parallel pipeline and a second crossing of the Colorado River. (P3-00005). PG&E constructed this line (now known as Line 300B) pursuant to newly-issued section 8 of the American Society of Mechanical Engineers' American Standard Association Committee B-31. (ASME B31.8). (P3-00006). This substantial revision was developed between 1952 and 1955 through the participation of utilities, steel suppliers, academics, and the Federal Power Commission, with the intent to establish a generally accepted standard across the country for safety in gas transmission and distribution work. PG&E participated in this effort.

In connection with hearings on PG&E's Third Supplemental Application, CPUC staff engaged in lengthy questioning of PG&E regarding construction practices in 1955. At a November 22, 1955 hearing, PG&E summarized its construction practices that were to be used in building the line:

- PG&E followed American Petroleum Institute (API) 5LX standards for procuring the pipe;[1]

[1] API pipe procurement standards require pipe to pass a variety of tests, including hydrotesting, bending, and chemical composition, before the pipe is shipped from the mill. These standards are discussed in more detail in section 2(b)(2) of this Subchapter.

- Pipe was to be tested hydrostatically at the mill;
- All welders on the project would be required to requalify pursuant to API Standard 1104;
- PG&E planned to conduct x-ray inspections of all tie-in welds, welds to fittings, and welds near river crossings, as well as between five and ten percent of all other girth welds. These inspections would be designed to inspect a sample of welds made by each individual on the project;
- Miter bends were not to be used in construction of the line;
- Significant dents and gouges were to be removed;
- Smooth bends were to be made on the job, but cold wrinkle bends were not to be allowed. All bends were to be at least two feet from any girth weld;
- All buried pipe was to be protected from external corrosion through primer paint, two coats of asphalt, and two layers of felt. This wrapping was to be inspected both in the yard where the pipe was stored before installation and on the job site;
- The line was to be protected using cathodic protection stations. Due to the protective qualities of the paint, asphalt, and felt coating, one station could protect between 40 and 50 miles of line;
- The line was to be cased where it crossed state highways and railways. Heavier pipe (thicker walls than required for the class location and MAOP) was to be used at secondary road crossings;
- The bottom of the trench dug for the line was to be free from rocks and other objects that might damage the pipe wrapping. Backfill was to be similarly free of harmful objects;
- The pipe was to be strength tested using gas or water as the test medium. In sections closer to the Milpitas Terminal, PG&E planned to conduct hydrotests to 125% of working pressure, as specified by ASME B31.8 section 841.412-D (1955). PG&E was also exploring the feasibility of conducting hydrotests in Class 2 locations, and planned to conduct such testing where practical; and

- Valves and blow-down facilities were to be spaced such that the longest it would take to blow down any section of pipe from maximum working pressure would be between 30 and 40 minutes.

(P3-00006). PG&E's plans for construction of the line were designed to exceed ASME B31.8 requirements to varying degrees. PG&E went beyond ASME B31.8 requirements in the frequent use of heavier (thicker-walled) pipe in areas where PG&E had reason to expect future urbanization, at river crossings, and in places with greater potential for corrosion activity. These construction practices were "on the conservative side," meaning they built in a safety margin beyond that called for by ASME B31.8.

PG&E also built the first of its northern backbone transmission lines (Line 400) during this pre-regulatory era. In the late 1950s, PG&E again forecasted that customer demand for natural gas would exceed the quantity of gas available to it from existing suppliers. To meet the growing demand, PG&E initiated a project to bring gas to California from Alberta, Canada. (P3-00007). At the time, the Commission was developing what would become the first General Order 112, but had not yet engaged in direct regulation of design, construction, and testing practices for natural gas transmission. PG&E's design, engineering, and construction of the pipeline was guided by standards set forth by ASME B31.8. These standards would soon be incorporated with modifications into state regulatory requirements.

2. PG&E Standards and Practices for the Design, Construction, and Initial Testing of Pipeline After 1961

a. Pipeline Design

(1) Regulatory History

The Commission adopted the 1958 ASME B31.8 with modifications when it first issued General Order 112. ASME B31.8 stated that the code was intended to assure that its design requirements were "adequate for public safety under all conditions usually encountered in the gas industry." GO 112 § 840.1 (RH-3). GO 112 includes a broad set of standards that can be categorized as applying to the design of natural gas transmission pipeline. These include establishing steel pipe design formulas (§ 841.1); guidelines for protecting pipeline from hazards such as landslides and erosion (§ 841.15); setting minimum cover standards (§ 203.1); and clearance between pipeline and other underground facilities (§ 841.161). These standards remained largely unchanged through GO 112-A (1963) (RH-4) and GO 112-B (1967) (RH-6).

Following implementation of federal laws and regulations for the natural gas industry, the Commission adopted GO 112-C (RH-32) in 1971 and incorporated federal pipeline safety standards. GO 112-C departed from the Commission's prior practice of implementing ASME B31.8, and instead incorporated the requirements of 49 C.F.R. Part 192. This practice continued through GO 112-D (RH-34) to the current GO 112-E (RH-36). Standards for pipe design in 49 C.F.R. 192, subpart C include design formula for steel pipe (49 C.F.R. § 192.105), design factor (§ 192.111), and general requirements for minimum wall thickness to withstand anticipated external forces and loads (§ 192.103).

(2) PG&E Standards and Practices

PGE adopted Standard Practice 1604 (S.P. 1604) to establish a uniform procedure for designing gas piping systems to meet the requirements of GO 112. This standard called for all new construction and reconstruction to meet design and pressure requirements set forth by the new regulation. (P2-902). This standard practice was superseded by PG&E Gas Standard and Specification A-34 in 1969 (A-34). (P2-903). A-34 is substantially the same as S.P. 1604. As revised over the last 41 years, A-34 is a primary guidance document for the design, construction, and initial testing of PG&E's natural gas transmission pipeline. Among other things, the standard requires that each transmission pipeline design be reviewed, approved, and signed by a professional engineer registered in California. (P2-36).

Starting with GO 112 in 1961, the Commission required all natural gas utilities to provide advance notice of transmission pipeline construction projects, including details regarding pipe design, construction, and planned hydrostatic testing. (RH-3). Archived PG&E records reflect the submission of many such reports to the Commission, in which PG&E provided the location, pipe specifications, and scheduled hydrotesting date to the Commission for transmission projects. (P3-00008, P3-00009, P3-00010). Over the years, the Safety Branch has observed PG&E's design and construction practices in the field, and has been present at some construction sites to inspect the pipeline and witness hydrotests.

Design and construction requirements are also specified in PG&E Gas Standard and Specification A-36 §§ 3-4 (1992) (P2-309). This document establishes general principles for many types of design and construction activities, including pipeline construction techniques in the trench, pipe handling, and inspection.

(3) Additional Design Practices that Promote Safety

PG&E has employed design and construction practices that go beyond those called for by state and federal regulation. These practices include particular methods used to address unique challenges presented by the varied geography of PG&E's service territory and proprietary tools used by pipeline engineers to design pipeline to withstand physical forces imposed by soil loading and vehicle traffic over the line.

(a) Addressing Design Challenges Presented by PG&E's Service Territory

Pipeline engineers are confronted with many challenging and unique circumstances presented by the geographic features present in PG&E's expansive service territory. One project that employed several additional design and construction practices to address unique geography was the construction of Transmission Line 57C that concluded in 2007.

Line 57C was built to parallel existing Line 57B connecting the McDonald Island storage field to PG&E's transmission network. These lines cross levee-protected islands in the Sacramento Delta. To avoid damaging the levee network during installation of the line, PG&E used horizontal directional drilling to string pipe underneath the levees and rivers in the Delta. This obviated the need to dig trenches across the levees.

Engineering analysis also revealed the potential for a levee failure to cause significant "scour," or soil erosion at the point of failure. PG&E determined the scour length for each location where Line 57C crossed a levee, and relocated the pipe or used additional horizontal directional drilling to place the pipe beyond the furthest extent of the scouring.

The soil surrounding Line 57C presented another challenge, as most of the soil within 12 feet of the surface consists of peat, and is considered a liquefaction zone in the event of a large magnitude earthquake. PG&E conducted additional engineering analysis to ensure that the pipe could withstand anticipated ground movement in such an event. One of the outcomes of this process was the decision to use manufactured induction bends that can better resist earthquake-induced ground movement.

As an additional safety measure, PG&E increased the wall thickness of pipe used in Line 57C to meet design specifications for a Class 3 location, even though most of the pipeline is in less-populated Class 1 or Class 2 areas.

(b) Proprietary Design Tools

For many of the last 55 years, PG&E pipeline engineers have used a proprietary tool known as PSTRESS to determine the effects of outside forces on the pipeline. The PSTRESS tool enables engineers to calculate stresses on buried gas pipeline subjected to any combination of the following types of loading: (1) hoop stress due to internal pressure; (2) circumferential bending stress due to traffic (vehicle and rail) load; (3) circumferential bending stress due to fill load; (4) longitudinal stress due to internal pressure; (5) longitudinal stress due to change in temperature; and (6) longitudinal bending stress due to pipe geometry and material mechanics. PSTRESS calculates total longitudinal and circumferential stresses based on user input of the pipe specification, trench configuration, internal gas pressure, and traffic loading. The calculations performed in

PSTRESS are based upon extensive academic research into the effect of loading on buried pipe.

PG&E has modified PSTRESS to more precisely address situations where the depth of cover on the pipe is relatively shallow (less than two feet). Where PSTRESS indicates that existing loading conditions are not within recommended tolerances, the engineer may call for additional fill over the pipe at locations where equipment will be crossing the line. Other mitigation options include placing a concrete slab or other form of bridge over the pipeline. Where none of these options are feasible, the engineer may relocate the affected area of pipeline.

b. Pipe Specification and Procurement

(1) Regulatory Requirements

Chapter 1 of GO 112 (1961) (RH-2) required pipeline operators to construct pipeline from qualified materials and equipment. The first category of "qualified" materials are those that conform to standards and specifications listed within the GO itself. § 811.1(a). Accepted standard specifications for materials, including line pipe, are set forth in Appendices A and B of GO 112, § 813.1. These appendices support the use of American Petroleum Institute (API) 5L and API 5LX material specifications for steel line pipe. Subsequent state and federal regulations have adopted API pipe specifications as qualified materials for the safe construction of pipeline.

(2) PG&E Standards and Practices

Following the implementation of state and federal regulations, PG&E's standards for transmission line pipe have called for API 5L and API 5LX line pipe. (P3-00011, P2-902, P2-903, P2-933, P2-939, P2-36). API standards cover welded and seamless pipe suitable for the conveyance of gas, water, and oil. These standards for pipe manufacturing require stringent testing and quality control to ensure that the highest quality pipe is used in a pipeline. API requirements address processes of manufacturing, material properties including chemical composition, tensile testing, and hydrostatic testing performed at the mill.

Line pipe specifications have evolved as PG&E's construction projects have utilized higher grade and larger diameter pipe. For example, PG&E's pipe specifications in SP 1604 (1965) included API 5L specifications for seamless and DSAW 35,000 psi SMYS pipe, API 5LX Grade X-42 42,000 psi SMYS pipe, and API 5LX Grade X-52 52,000 psi SMYS pipe. By 1974, PG&E's pipe specification requirements expanded to include API 5LX Grade X-60 60,000 psi SMYS and API 5LX Grade X-65 65,000 psi SMYS DSAW pipe for use in larger diameter applications. *See* A-34 Change 3 (1974) (P2-903).

PG&E currently requires all steel pipe purchased for use in its natural gas piping systems to meet API 5L[2] specifications. (P3-00012). This standard is annexed to procurement contracts, and governs conditions of acceptability. (P3-00013). The standard assures that mill-furnished pipe meets certain chemical properties (A-16 § 2), mechanical properties (§ 3), is inspected during the pipe production process by a PG&E Supplier Quality-designated inspector (§ 4), is hydrostatically and non-destructively tested (§§ 6-7), meets defect repair requirements (§ 8), is marked to facilitate traceability (§ 9), and is shipped in accordance with applicable PG&E standards (§ 10). PG&E A-16 requirements exceed the API 5L standard by calling for lower carbon equivalent requirement (0.40% compared to API at 0.43%), higher Charpy test values,[3] tighter tolerances for defect repairs and 100% inspection on each mill run.

c. Pipe Handling, Storage, and Transportation

(1) Regulatory Requirements

GO 112 provides the general guidance that "[c]are <u>shall</u> be taken in the selection of the handling equipment and in handling, hauling, unloading and placing the pipe so as to not damage the pipe." GO 112

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[2] API discontinued the use of 5LX specifications in 1982. All grades of pipe are now incorporated in API 5L specifications.

[3] The Charpy impact test, also known as the Charpy v-notch test, is a standardized high strain-rate test which determines the amount of energy absorbed by a material during fracture. This absorbed energy is a measure of a given material's toughness and acts as a tool to study temperature-dependent brittle-ductile transition.

§ 841.271 (underlining in original). This requirement continued unchanged through the initial adoption of GO 112-B. An amendment to GO 112-B in 1970 incorporated 49 C.F.R. § 192.65, which provided that the transportation of certain pipe by rail must be done pursuant to API standards, or be pressure tested if the pipe were transported before 1970. This requirement was amended in 2010 to provide some additional transportation guidance for pipeline transported by ship or barge, again referring operators to API standards. See 49 C.F.R. § 192.65.

(2) PG&E Standards and Practices

PG&E currently implements requirements for transporting pipelines set forth in 49 C.F.R § 192.65 through Gas Standard and Specification A-14. (P3-00014). PG&E's standards and practices also expand upon regulatory requirements for the safe handling, storage, and transportation of pipe. (P3-00015). PG&E Standard Practice 522.1-2 (1963) (S.P. 522.1-2) established procedures to ensure that pipe was handled and stored in a manner to avoid damage to any part of the pipe or coating. Generally, S.P. 522.1-2 was meant to ensure that pipe did not sustain damage such as grooves, dents, gouges, or flattening while in transit between the mill and the trench. S.P. 522.1-2 (as well as its successors) also provides particular instruction in the stacking, loading and unloading, transportation, and storage of pipe.

PG&E standards articulate special handling instructions when placing the pipe into the trench in order to prevent damage to the pipe and coating. Current Gas Standard and Specification A-36 calls for specific clearances between pipe and trench walls. It requires construction personnel to clear the trench of rocks and other hard substances prior to laying the pipe, and for surrounding the pipe with backfill of sand or other fine materials to protect the pipe and protective coating from rocks and other sharp objects. (P2-309). This standard also calls for pipe to be transported into the trench using specialized lifting equipment to avoid bending, denting, buckling, scratching, or otherwise damaging the pipe.

d. Welder Qualification and Weld Inspection

(1) Regulatory Requirements

Pipeline safety laws have required each utility or operator to establish and qualify a welding procedure for use in constructing girth welds, and further specified that each welder must qualify under the procedure before working on transmission pipe. Generally speaking, natural gas utilities and operators could satisfy the requirement by creating a welding procedure that followed specifications of API Standard 1104, "A Standard for Field Welding Pipe Lines."

Regulations also have required natural gas utilities and operators to inspect welds on pipe intended to operate above 20% SMYS to ensure that the welds conform to standards of acceptability. The method of inspection was not originally specified, but could include nondestructive testing (visual, radiographic, or magnetic particle testing) and destructive testing. In 1961, California natural gas utilities and operators were required to test 100% of welds at tie-ins, infrastructure crossings, taps, and other required areas, 30% of welds in Class 3 and Class 4 locations, and 20% in Class 1 and Class 2 locations, all on a daily sampling basis to ensure that each welder's work was inspected. These standards changed in 1971 to require 100% inspection of welds in Class 3 and 4 locations if practical, but not less than 90%. (RH-32). Pursuant to GO 112-E and the incorporated federal regulations, California utilities and pipeline operators must currently inspect 10% of Class 1 girth welds and 15% Class 2 girth welds all on a daily sampling basis. Every Class 3 and 4 girth weld and each girth weld at an infrastructure crossing must be inspected unless impracticable, and in no case may less than 90% of these welds be inspected. See 49 C.F.R. § 192.243(d).

To pass inspection, welds must be free from certain types of defects specified in federal and state regulations. Tolerances for welding defects were first set out in GO 112 § 829, and are currently found at 49 C.F.R. § 192.241(c) (incorporating API 1104 § 9).

(2) PG&E Standards and Practices

PG&E standards have implemented the welding requirements set forth in state and federal regulations. PG&E issued Standard Practice 1602 (S.P. 1602) in 1963 to establish a uniform welding procedure for constructing girth welds. (P2-1271). This standard also set forth welder qualification requirements, tests, and inspection procedures for welding API 5L and 5LX pipe operating at or above 20% SMYS. These standards now appear in PG&E Gas Standards and Specifications D-22 (2009) (P2-10), D-30.2 (2009) (P2-1282), D-30.4 (2009) (P2-1285), and D-31 (2009) (P2-1270).

PG&E issued Standard Practice 1605 (S.P. 1605) (P2-1286) in 1963 to establish a minimum weld inspection procedure for all gas pipe systems and to satisfy inspection requirements set forth in GO 112. This standard called for welds to be inspected on a sampling basis sufficient to establish the performance of each welder, and in percentages that met the regulatory requirements. Requirements in S.P. 1605 are presently found in PG&E Gas Standard and Specification D-40 (2009) (P2-1296).

(3) PG&E Welding Apprenticeship Program

Certain of PG&E's training programs have been recognized in the past for their quality. (P3-00016). One training program PG&E has historically offered bears special mention. PG&E offers a welding apprenticeship for General Construction Arc Welders and training for Division Gas Fitters. The welding training shop is located in San Ramon. Through the "Power Pathways" program, which connects the Company to six community colleges, PG&E recruits graduates of community college welding programs. In addition to those recruits, field employees can also enter the apprenticeship program. The apprenticeship program is rigorous: It extends over 36 months and involves 6000 hours of in-the-shop and on-the-job training. PG&E now employs a training coordinator dedicated to the welding apprenticeship program who visits the welding apprentices in the field.

e. Initial Testing Requirements

(1) Regulatory Requirements

Regulations did not call for natural gas utilities to pressure test transmission lines until GO 112 in 1961. (RH-2). Federal regulations covering strength testing in 49 C.F.R 192, subpart J were incorporated by GO 112-C (1971) (RH-32) and remain in effect in current GO 112-E (RH-36).

(2) PG&E Standards and Practices

S.P. 1604 called for construction foremen to observe strength test requirements set forth by the responsible pipeline engineers, and record information from the actual test on a "Strength Test Report" to be returned to District Superintendents and other appropriate personnel. *See* S.P. 1604 (1965) (P2-902). This standard also specified the conditions under which strength tests were required and the test medium and pressure to be used. Strength testing requirements are presently set forth in PG&E Gas Standard and Specification A-34, and have been since 1969. The various versions of A-34 have called for strength testing to be carried out pursuant to the design pressure and class location as specified in GO 112. (P2-903).

TAB 13

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6B
OPERATIONS AND MAINTENANCE ACTIONS TO PROMOTE SAFETY ON PG&E'S GAS TRANSMISSION SYSTEM

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A. PG&E Has Sought to Operate and Maintain its Transmission Pipelines to Promote Safety.

This Subchapter responds to Directives 3.A-3.C of the OII. It describes the actions PG&E took within the areas of operations and maintenance (O&M) to promote safety on its gas transmission pipelines between 1955 and 2010.

This Subchapter sets the regulatory context and then describes, for each regulatory topic area, PG&E's operational and maintenance actions and procedures to promote safety. The discussion follows the organization of Subparts L and M of 49 C.F.R. Part 192. Subpart L sets forth the present-day regulatory standards that govern natural gas pipeline operations. Included in the discussion of operations are PG&E's Training and Operator Qualification Programs referenced in Subpart N. Subpart M sets forth the regulatory standards that govern maintenance activities, including repairs. PG&E's response generally tracks major O&M subject areas described in subparts L and M.[1] Although these subparts did not come into effect until 1970, they provide a framework for organizing a discussion of O&M actions and procedures during the entire time period covered by the OII.

1. Overview of O&M Regulatory Requirements

The Commission's adoption of GO 112, effective July 1961, introduced operations and maintenance regulatory requirements. Chapter V of GO 112 mandated the development of and adherence to a "plan covering operating and maintenance procedures" for day-to-day operations and emergencies and established requirements relating to patrolling, corrosion, leak repairs, valve inspection, odorization and operating pressure. In 1970, the Department of Transportation Office of Pipeline Safety (OPS) promulgated federal regulations for pipeline safety. In addition to the types of operational requirements included in GO 112, Subpart L of the new federal regulations addressed "Operations," a subject area that included line surveillance, emergency plans, and investigation of failures. Subpart M added maintenance requirements related to line markers, field repairs and testing

1 PG&E has not discussed every subject area in subpart L (e.g., it has not included a discussion of its procedures for tapping pipelines under pressure) or subpart M. It has, however, addressed most subject areas in subparts L and M.

of repairs, and abandonment of facilities. GO 112-E (and several predecessor GO 112s going back to 1970) adopt Part 192's subparts, including subparts L and M.

2. Operations Activities To Promote Safety

a. Damage Prevention and Public Awareness Programs

PG&E's efforts to prevent third party damage are critical to maintaining the safety of its gas transmission system. In its latest annual report, the Commission's Safety & Reliability Branch declared that in 2007, "the single most common cause of [] reportable gas incidents was excavations." (P3-10,001). The Safety Branch's report from a decade earlier reported that dig-ins caused about 60% of the reportable gas incidents for 1997. (P3-10,002).

Beginning in 1982, 49 C.F.R. § 192.614 required operators to implement programs to prevent damage to pipelines due to excavation. This regulation followed the general program recommendations of the American Petroleum Institute's Recommended Practice 1162. (Prior to 1982, the regulations did not require operators to maintain formal damage prevention programs). Since 1994, § 192.616 has required operators to develop and implement a written continuing public awareness program. Damage prevention and public awareness efforts are discussed together in this section.

PG&E's electronically accessible Damage Prevention Manual provides, in one location, regulatory and company damage prevention requirements, policies, and procedures for gas, electric, and fiber facilities. Principal elements of PG&E's Damage Prevention program include:

- Mark and Locate and the One-Call System
- Installation of Line Markers
- Public Awareness Program
- Collaboration with Outside Groups.

(1) Mark and Locate and the One-Call System

PG&E participates in a statewide "one-call" system—the Underground Service Alert (USA). This system allows contractors, homeowners, municipalities, utilities, and others to call one number (8-1-1) when they are planning to excavate anywhere in California. The USA service then alerts potentially affected utilities. The service generates and transmits to PG&E a "USA ticket" anytime someone is planning to dig near any PG&E facilities (including gas transmission, gas distribution, electric transmission and distribution, and fiber). Every year PG&E receives about 500,000 USA tickets, of which 300,000 require a response by the Company.

The tickets are processed by PG&E's ticket handling software, which sends the ticket directly to a Company locator to respond. Locator personnel are equipped with mobile computers showing facility maps to allow them to respond quickly and efficiently to the tickets. Each ticket is screened by the locator to determine if PG&E facilities may be in conflict with the excavation, which would require surface marking, and determine if a field meeting with the excavator is necessary.

When surface marking is required due to a conflict, yellow paint is sprayed on the ground to mark the location of the facility, or another appropriate marker is used. After marking, PG&E may then contact the excavators for further information about the planned excavation as required. If work is expected to come within five feet of gas transmission facilities, PG&E's procedures call for employees to be present at the location while the third party digs around the facility. No power equipment is permitted to operate within 12 inches of the gas transmission line.

PG&E has employed procedures meant to prevent damage to the Company's pipelines throughout the time period covered by the OII, even if the practices were not set out in a formal damage prevention program. Some of these procedures have been described in correspondence with the Commission. In 1966, for example, the CPUC requested that PG&E describe the "most significant actions taken by PGandE in an effort to minimize the number of accidents and interruptions of gas service, which are or could be caused by others." (P3-10,003). As PG&E described, its damage prevention procedures at the time included, among other things, providing information about the location of its gas facilities to individuals who requested it before beginning construction; using pipe locators and marking facilities in the field as needed when excavations were to take place; standing by at the project as needed; and exposing pipelines as needed to protect them. PG&E distributed wallet cards to excavators and members of the public with a telephone number to call to locate underground facilities or in the event of an emergency. The Company also exchanged information with governmental agencies and other utilities to avoid potential conflicts with other underground facilities. PG&E Report to CPUC, Operating and Maintenance Procedures for Major Gas Pipelines, section 8 (1966) (1966 O&M Report) (P3-10,004).

In this era, PG&E had a standard practice of requiring that at the time of installation adequate minimum ground cover be provided above gas mains. The amount of cover required might be greater, for example, in "areas where farming or other operations might result in deep plowing." PG&E Report to CPUC, Pipeline Surveillance Procedures and Records and History File Description Pipeline Patrolling, Standard 463-4 (1967 Surveillance Report) (P3-10,005). PG&E had also established an approach for working with landowners to ensure safety when the landowners planned to cultivate or level the ground near older facilities buried close to the surface. 1966 O&M Report, section 6 (P3-10,004). The Company employed a standard for "Use of Company Rights of Way (Fee and Easements) By Others," which addressed safety and legal issues relating to third party activities near pipelines. (P3-10,005).

In 1974, PG&E collaborated with the Pacific Telephone Company to develop an "information clearinghouse plan" that would establish a "one-number call system." (P3-10,006). The "clearinghouse plan" had a call center that would contact participating utilities by teletype about planned excavations that might affect their facilities. PG&E's implementation of an early one-call system in 1974 preceded regulatory requirements for a one-call program by a number of years.

(2) Line Markers

PG&E's transmission lines are installed with above-ground markers identifying their location. (Ex. P3-10,007). The markers include non-metallic marker posts, steel marker posts, pipeline warning decals (in English and Spanish), and aerial pipeline markers (for identification by aerial patrol aircraft). In addition, although not required by regulation, signs are placed at any location where PG&E's transmission lines traverse navigable waterways to alert vessel operators to the presence of the lines.

PG&E has long used "readily identifiable markers" on its pipelines to minimize damage caused by farmers, excavators, or others and to assist PG&E's own employees in finding pipelines in remote places like the desert. (P3-10,004). By 1955, PG&E practices specified the particular type of marker that would be used according to the location on a pipeline; the Company had developed design drawings for those markers, e.g., a "Steel Marker Post for Underground Gas Facilities." (P3-10,005). PG&E used this steel Marker Post line marker design since at least 1955.

(3) Public Awareness Program

An important component of PG&E's damage prevention program is making the public aware of the need to alert PG&E in the event of planned excavations. PG&E's Public Awareness Program is guided by several PG&E procedures:

- Risk Management Procedure 12. RMP 12 sets forth PG&E's plan to enhance public safety and environmental protection through increased public awareness and knowledge. (P2-398).
- Safety Health & Claims (SH&C) Procedure 103, Public Safety Information Program, directs the delivery of information to customers and the public regarding the safe use of electricity and natural gas and safety awareness around the company's gas and electric facilities. (P3-10,008, P3-10,009).

- SH&C Procedure 104, outlines the actions an employee takes when observing unsafe work practices by a responsible party working around or near overhead and/or underground gas, electric, and fiber optic cable utility facilities. (P3-10,010).

The procedures describe a number of public awareness actions that PG&E takes. PG&E sends out public safety mailings to new customers and, at least every other year, to property owners who are not customers but who live within a certain distance of a transmission pipeline. PG&E also provides information to customers through messages attached to bills regarding safety issues such as dig-ins and leak repairs.

The Company reaches out directly to farmers, ranchers, agricultural workers and farm associations through mailings and presentations, providing materials in Spanish and English. It also conducts outreach to the construction industry, annually distributing bilingual safety materials to approximately 50,000 excavators within its service territory. See the Contractor Beware Program website, www.pge.com/contractorsafety/. Program materials for excavators include "Contractor Beware" safety booklets; a safety trainer's guide; a safety video; and a "Contractor Beware" poster. The "2010 Excavation Safety Guide & Directory" was sent to over 114,000 excavators across California by the Pipeline Association for Public Awareness (PAPA), of which PG&E is a contributing member. The guide provides comprehensive information on a variety of pipeline safety topics. See website for 2010 Excavation Safety Guide & Directory, http://www.excavationsafetyonline.com/esg/index.php

The Company seeks out opportunities to address the public about pipeline safety, for example at county fairs, and to distribute materials. PG&E visits schools to educate children about the hazards associated with its gas facilities. The school programs discuss above-ground markers and provide information about how to contact PG&E when activities are observed around a gas pipeline.

PG&E also works with first responders to prepare for a coordinated response in the event of a gas emergency and to help prevent damage to pipelines by the public. PG&E's local transmission districts host periodic first responder meetings to which local fire departments, law enforcement, the California Highway Patrol, and, where appropriate, the Coast Guard, are invited. When these meetings are held, PG&E representatives describe the gas emergency plans and safe practices for dealing with fires fed by natural gas and discuss the Incident Command System approach (discussed below) to coordinating response efforts by PG&E and first responders. PG&E additionally discusses the ways in which first responders can assist in preventing damage to pipelines from third parties, and thereby prevent gas incidents. PG&E also periodically conducts joint emergency response exercises with first responders in local communities to enhance unified response capabilities in the event of an emergency. (P3-10,018). On its website, PG&E hosts a first responders page through which first responders can sign up for classes and request materials. See http://www.pge.com/firstresponder.

Public awareness programs are not new to PG&E. To take one period as an example, in the late 1970s, the Company employed an audio-visual presentation called "Make Every Dig a Safe Dig" that it presented to construction workers. (P3-10,019). Around the same period, the company made a safety film called "Dig Our Message, Not Our Pipelines," that it shared with contractors and public safety organizations. (P3-10,020). The Company also distributed a booklet called "Emergency Control of Natural Gas." to first responders. (P3-10,021).

(4) Collaboration with Outside Groups

PG&E works with outside organizations that focus on damage prevention and raising public awareness of the risks associated with excavation.

PG&E is one of the sponsors of the Common Ground Alliance (CGA). In 1999, OPS studied one-call systems and damage prevention best practices, producing a report titled “Common Ground.” CGA was formed to continue the damage prevention work captured in the OPS report. It is a “member-driven association dedicated to ensuring public safety, environmental protection, and the integrity of services by promoting effective damage prevention practices.” See http://www.commongroundalliance.com. A PG&E representative is the current co-chair of the California Regional CGA Committee; other employees participate in subcommittees and in roles in the national organization.

CGA evaluates and promotes the use of best practices related to damage prevention and pipeline safety by engaging stakeholders (e.g., operators, first responders, and excavators). (P3-10,022). It also holds events to raise public awareness, for example through sponsoring a national 8-1-1 dig-in prevention awareness day. (P3-10,023). CGA has 44 sponsor organizations, including PG&E; 180 member organizations; and 1400 individual members. The September 2010 edition of the CGA newsletter illustrated PG&E’s involvement in CGA’s work by highlighting television coverage of a safety demonstration the Company performed in collaboration with the Chico Fire Department and California Department of Water Resources.

PG&E also subsidizes programs through USA North and USA South that provide information to excavators about pipeline damage prevention. In 2009, USA North, which covers PG&E’s service area, hosted 27 events for excavators. (P3-10,024). A PG&E representative sits on the governing boards of both USA North and USA South.

Additionally, PG&E is a member of PAPA. PAPA is a national non-profit organization that provides educational information regarding pipeline safety and emergency preparedness to the public, governmental entities, and other organizations and conducts safety and emergency readiness programs across the country.

PG&E has been involved in damage prevention organizations since at least 1966. In 1966, the Company reported in a letter to the

Commission that, as a member of the AGA, it had "been working with members of the various gas utilities in the United States in preparation of a public safety program designed to minimize the occurrence of accidents involving gas facilities." (P3-10,003). PG&E noted that although it had already taken most of the actions covered by the AGA program, it "anticipated that the acceptance of such a program on a national basis will result in more publicity regarding the necessity of preventive action, not only by other utilities, but by members of the public."

b. Emergency Plans

Under Subpart L at § 192.615, the 1970 federal regulations introduced the requirement that operators establish written procedures to minimize the hazards resulting from a gas pipeline emergency. PG&E maintains a current Company Gas Emergency Plan that outlines the responsibilities and procedures to safeguard life and property and maintain or restore service during a natural gas emergency. (P2-317). A gas emergency is defined as an actual or potential hazardous escape of gas, an extreme over-pressure or under-pressure situation, an interruption of gas supply, or a combination of these events. Department directors are required to ensure that the department gas emergency plan is reviewed with all employees at least annually. Each field division also maintains its own gas emergency plan.

(1) The Company Gas Emergency Plan

In the event of a local gas emergency that (a) involves local personnel and (b) can be resolved without assistance from another department within PG&E's gas transmission operations (e.g., a gas leak or gas dig-in), PG&E may activate a local Operations Emergency Center (OEC) to coordinate emergency activities. In the case of larger-scale emergencies, the Gas Restoration Center (GRC) may be activated (e.g., if emergency response requires moving personnel or equipment). Some emergencies require enterprise-wide coordination, such as the Loma Prieta earthquake or the San Bruno tragedy. In these instances, PG&E activates the Corporate Emergency Operations Center (EOC).

Gas Control in San Francisco, which is discussed in more detail below, performs a key liaison function during a gas emergency. During an emergency, Gas Control provides critical information and input for the Incident Command process. Because it continuously monitors the system, Gas Control is often the first PG&E organization to learn about an event or incident. It can provide information that helps inform the decision whether to activate an emergency command center and at what level (OEC, GRC, and/or EOC). Once an emergency command center is activated, the highest level command center coordinates all response activity surrounding the event.

The Company has considered measures to take in the event of an emergency since the beginning of the OII period. A 1956 memo to division managers "outlines emergency measures to be followed in the event of an interruption to the gas supply due to the failure of some facility either of this company or its gas suppliers." (P3-10,025). The memo focused on how to appropriately and safely reduce the use of gas by customers following an emergency that interrupts gas supply. It included a discussion of the best way of communicating to the public through media sources during an emergency and a reminder that divisions should "be prepared quickly to effect the emergency steps" and should channel their orders through Gas Control.

To facilitate emergency response before the SCADA system and other technological advances that permitted a coordinated response, the Gas department put into service a mobile emergency command center. "Mobile Command Post 1," first deployed in San Francisco in 1982, was equipped to provide rapid, on-the-spot response coordination in the event of a gas incident on the Company's transmission or distribution lines. (P3-10,026; P3-10,027). A few years later, the Gas department put into service another Mobile Command Post in the East Bay. When the

Company began to use SCADA, a SCADA terminal was installed in the Mobile Command Post. Use of the mobile centers dropped off following advances in SCADA and remote communications, but PG&E will be deploying them again in the near future.

(2) Incident Command System

PG&E utilizes the Incident Command System (ICS), in accord with the National Incident Management System (NIMS) principles, as its approach for responding to emergencies. Within the gas industry, PG&E was among the first to implement ICS. The PG&E corporate-wide transition to ICS in 2006 was preceded by the Gas Transmission organization having already implemented an ICS-type structure about ten years earlier.

ICS is a standardized, on-scene, incident management approach used by different organizations and agencies nationwide for responding to a wide variety of emergency situations (e.g., floods, earthquakes, gas main ruptures). ICS establishes common processes and procedures for implementing a coordinated emergency response. For example, ICS establishes common terminology for use in emergency response; assigns command positions with consistent titles and responsibilities; and utilizes an Incident Action Planning format to establish clear incident objectives.

(3) Training and Exercises

PG&E trains employees on how to use ICS through a curriculum it has developed based on ICS training materials used for government employees. Additionally, all PG&E employees involved in emergency response take, at a minimum, the Federal Emergency Management Agency (FEMA) courses ICS-100 (Intro to ICS) and ICS-200 (ICS for Single Resources and Initial Action Incidents). Key incident commanders and officers also receive classroom training to understand their roles in ICS. PG&E has shared its ICS curriculum with state officials. The curriculum is being considered in the development of national FEMA standards for emergency training.

PG&E conducts an emergency exercise each year that simulates a company-wide emergency. Key emergency management personnel are required to participate. In addition, all local districts and divisions are required to plan and simulate an emergency annually in their local area. Primary position leads in the ICS and all back-up personnel are required to participate in these exercises.

(4) Working with First Responders

As discussed, PG&E works with first responders to prepare for undertaking a coordinated response in the event of a gas emergency. During a real gas emergency, the Liaison Officer designated under ICS coordinates with local first response agencies, as well as with other federal, state, and local agencies.

PG&E has worked with first responders since at least the 1960s. In response to a request from the Commission in 1968, the Company provided a detailed report on the "liaison procedures that have been established with fire departments and other disaster agencies." 1968 Disaster Liaison Report (P3-10,028). The report details the efforts made by local PG&E field offices to create a connection with police and fire departments; attaches a copy of a safety booklet provided to first responders; and includes an outline for a six-hour safety presentation regularly provided to fire departments.

c. Investigation of Failures and Reporting of Incidents

Regulations requiring failure investigations were introduced by DOT in 1970. GO 112-E incorporates the federal reporting requirements, and at § 122.2, also introduced a separate reporting requirement to the Commission when an incident occurs in the vicinity of the operator's facilities that has attracted public attention and appears to involve natural gas, whether or not the operator's facilities are involved. PG&E reports incidents to the CPUC and PHMSA in accordance with the applicable reporting requirements.

Prior to GO 112-E, the Commission had not adopted a formal incident reporting requirement. PG&E nonetheless made reports to Commission staff as far back as the 1950s about the results of incident investigations. (P3-10,029; P3-10,030; and P3-10,031).

PG&E maintains an in-house testing organization called Applied Technology Services (ATS) that is available to investigate material failures. ATS is a multi-disciplinary team of approximately one hundred engineers, scientists and technicians that perform failure analysis, inspections, and performance assessments and evaluations on a wide variety of components. (P3-10,032). ATS serves as the in-house resource for investigation of significant failures of pipeline facilities or equipment or failures that do not have an obvious cause. ATS and its predecessor investigative organizations trace back to the formation of PG&E in 1905.

d. Regulating Pressures

PG&E regulates pressure on its pipeline system through pressure regulator stations and over-pressure protection devices. Utility Standard S4540, *Gas Pressure Regulation Maintenance Requirements*, governs how the company maintains these devices, which operate to keep pressure within specified limits. (P2-110). The devices are required to be inspected and maintained at regular intervals.

As described further below, PG&E operates the gas transmission system from Gas Control in San Francisco (and maintains a fully-equipped, back-up facility in Brentwood, CA). Gas Control continuously monitors the pressure of transmission pipelines through the Supervisory Control and Data Acquisition system (SCADA). SCADA is equipped with alarms that are triggered to alert Gas Control that a line may be approaching excessive or insufficient pressures. There are four types of SCADA alarms: High, High-High, Low, and Low-Low. High-High and Low-Low alarms indicate a critical operating condition. Gas Control will take appropriate action following any type of alarm, such as reducing pressure on a line if the pressure climb cannot be explained.

PG&E's standards for controlling pressure on its gas transmission lines date back to at least 1967. The 1967 Surveillance Report submitted to the Commission includes "standard procedures and forms used for proof testing and establishing or changing MAOP," including Standard Practice 1604, Design and Test Requirements for Gas Piping Systems. (P3-10,005). The year before that Report, PG&E explained to the Commission that "[m]aximum operating pressures are established by the Company for each pipeline based on specifications, condition of the main, and public exposure. A review is made annually of the established pressures and changes are made if required. In addition, an analysis of the operating pressures and stress levels is made in conjunction with population density surveys and any changes are reflected in the annual review." 1966 O&M Report, section 1, Operating Pressure and Stress Level (P3-10,004).

e. Control Room Management

The first federal regulations regarding control room management were introduced in 2009, and will take full effect in October 2011. PG&E had already undertaken a variety of actions to promote safe control room practices prior to the development of these new regulations. By the mid-2000s, PG&E had introduced policies to mitigate workplace fatigue. (P3-10,033). When building a new control room in the Brentwood facility in 2004 to 2005 and upgrading the Gas Control room in San Francisco soon thereafter, the Company conducted ergonomic assessments, installed adjustable desktop console work stations, provided exercise equipment, and made sure the work spaces had natural light.

A PG&E representative was actively involved in the work of the AGA Gas Control Committee that studied the PHMSA control room regulations when proposed and developed white papers on the Committee's findings. In turn, the federal regulators considered input on the rule presented by the AGA and other industry groups when drafting the final regulations. Some of the practices that AGA included in its white papers mirrored practices already in place at PG&E and at other operators.

(1) Gas Control Functions

The two primary functions of Gas Control are to monitor and operate the gas system safely and reliably and to respond appropriately to abnormal and emergency operating conditions. The key is to balance the complex, interconnected transmission system to maintain safe pressures, while sustaining enough pressure to meet customer demand. Advance planning, anticipating customer needs, forecasting the weather, and handling system anomalies are all critical tasks. Gas Control Operators must complete Operator Qualification requirements to qualify to perform the tasks.

Gas Control is a critical hub for communications about the gas system. There are signs on PG&E's pipeline markers and stations alerting the public to call Gas Control if they observe any hazard. First responders (both from PG&E and first responder agencies such as local fire departments) are trained to call Gas Control in the event of any gas emergency. Gas Control is also notified about gas leaks or other incidents through internal calls to Dispatch or through customer calls to Customer Service Representatives, who in turn notify Dispatch.

(2) Clearance Procedures

PG&E's Gas Clearance procedure, set forth in Work Procedure 4100-10, details the process for working on the pressurized gas transmission system in a safe manner. (P2-314; P3-10,034). Gas Clearance involves isolating the portion of pipeline where the work is to occur. The written clearance is drafted by the Clearance Supervisor, reviewed, evaluated by local area supervision, and submitted to Gas Control for approval. All changes are incorporated and the clearance is coordinated through Gas Control.

(3) Back-Up Gas Control Facility

In addition to Gas Control in San Francisco, there is a back-up unmanned facility in Brentwood, CA for use in an emergency. This facility is fully redundant, so that the gas transmission system can be operated from either San Francisco or Brentwood. The

Brentwood facility is tested each quarter to ensure that all systems are up-to-date and ready for use in the event of an emergency that requires the transfer of gas control functions to Brentwood.

(4) Meteorology Department

PG&E maintains a meteorology department in San Francisco, located close to Gas Control. Temperature and weather forecasts are provided three times each day to Gas Control and are used to forecast gas demand to avoid customer curtailments. Extreme weather patterns can impact the gas transmission system. PG&E's meteorologists respond to needs within the widely diverse PG&E service territory, and the group is able to provide specific forecasts for each sub-climate in the service territory. Meteorologists participate in the emergency response centers (EOC, OEC, GRC) when the centers are opened to respond to an incident.

(5) Supervisory Control and Data Acquisition (SCADA)

The SCADA system allows Gas Control to remotely monitor the gas transmission system facilities in real time. The SCADA system also is used to remotely control major interconnection, compressor and regulating transmission stations. SCADA contains 14,000 analog and digital sensor points and 800 supervisory control points that work together to provide accurate real-time operating data in a usable format.

SCADA allows operators to monitor the gas transmission system and control operating pressures remotely through approximately 300 remotely-controlled valves and compressors along PG&E's transmission system. The SCADA system can only be operated by Gas Control Operators at Gas Control in San Francisco (or the back-up Brentwood facility). Other personnel within PG&E can view SCADA information in real time through a secure SCADA Web Server. Gas Technicians in the field use the SCADA Web Server to troubleshoot or help pinpoint issues on the gas transmission system or in regulator and compressor stations. Gas Transmission Planning Engineers also use the SCADA Web

Server to monitor local area system performance during clearance work and during peak demand days.

PG&E upgraded its SCADA system in 2005 and, at the same time, updated the Remote Terminal Units—the 356 units that provide electronic signals to SCADA from field devices transmitting pressure flow, gas quality and equipment status data. When upgrading the SCADA system, PG&E and its software vendor (Citect) populated the system with station drawings containing the same operating diagrams that the field personnel have available. SCADA's detailed schematics allow gas operators to communicate with gas mechanics and technicians when, for example, a technician is working on equipment inside a regulator station. (P3-10,035).

The introduction of the first SCADA system in the 1980s marked a significant milestone in PG&E's efforts to promote pipeline safety. Previously, PG&E did not have the ability to monitor and operate the entire system from a single location. When an operator needed to increase or decrease pressure he or she telephoned or teletyped instructions to personnel manning stations and load centers. In those times, gas control "information flowed on little pieces of paper and through phone calls. Pressure and volume data records and calculation were noted by hand before they were called into System Gas Control." PG&E Week, *Faster information flow allows for more control over the gas business*, July 14, 1989, at p.1 (P3-10,036). In addition to significantly advancing day-to-day operations capabilities, the introduction of SCADA allowed Gas Control to respond more quickly in an emergency.

Over time, SCADA allowed the field gas control functions to be consolidated with Gas Control. Prior to the mid-1990s, there were ten field control centers, each of which were staffed 24/7, in addition to Gas Control in San Francisco. Personnel assigned to these field control centers monitored and operated their areas of geographic responsibility in coordination with Gas Control. Following significant planning, the field control centers were gradually consolidated. SCADA made this consolidation technologically possible, by allowing compressor and regulator stations to be controlled remotely. Starting in the mid-1990s, the number of field control centers was reduced from ten to one, and then in 2010 a final consolidation was made to Gas Control in San Francisco.

f. Training and Operator Qualification

PG&E has a centralized training program and a comprehensive operator qualification program to promote the safe operation of its transmission pipelines.

(1) Training Program

In the late 1990s, PG&E centralized its training functions into the "PG&E Academy," with facilities located in San Ramon and Livermore. The Academy offers training across skill areas required by O&M pipeline personnel. Training may be instructor-led, web-based, hands-on, through demonstrations, or a combination. The instructors themselves undertake an eleven-day training program before they are fully qualified to train others.

For the past four years, the Academy has used a "task analysis" for developing training. Task analysis involves comparing and analyzing the step-by-step approaches of experienced personnel to develop the most effective and detailed instructions for how to accomplish a given task. The Academy's curricula incorporate industry best practices and are pilot tested before they are rolled out as regular programs.

Certain positions in Operations and Maintenance, such as Gas Transmission Mechanic, require personnel to complete an apprenticeship program. An apprenticeship requires classroom study and testing, on-the-job training, and individual study. PG&E Academy provides the classroom portion of the program. On-the-job training is performed under the experience of a journeyman. An apprenticeship can last between one to two years.

(2) Sim City Training Facility

"Sim City" is a simulated neighborhood located at PG&E's Livermore Training facility that provides hands-on training environment for PG&E's gas transmission and distribution operations and maintenance employees. At the time of its construction in 2008, Sim City was one of fewer than ten such training facilities at natural gas utilities nationwide. Sim City is a simulated, mini-neighborhood, complete with streets and mini-houses. (P3-10,037). Pipelines have been buried in the "neighborhood," and above-ground features constructed. The facilities at Sim City are appropriate for training both transmission and distribution O&M personnel. Sim City is used for training in three key areas: Mark and Locate, Leak Survey, and Cathodic Protection testing. The skills developed apply both to transmission and distribution facilities.

- *Mark & Locate*. Employees are first trained on the applicable regulations and standards and the proper use of the locating instruments. Once they are proficient in a classroom setting, they practice the skills in the streets of Sim City. An instructor observes the employees and provides coaching and correction.
- *Leak Survey*. An electronically controlled system simulates leaks at various locations in the Sim City neighborhood. Once again, the employees first receive classroom training, and then exercise their skill in a simulated situation.
- *Cathodic Protection Testing*. Cathodic protection systems are in place in Sim City and the instructors have the ability to simulate real world instances of cathodic protection anomalies. The employees use their classroom skills to become proficient with the tools and processes.

(3) Operator Qualification

Federal regulations require operator qualification (OQ) to perform certain tasks affecting the integrity of a pipeline. This OQ requirement was introduced in 1999 in Subpart N of 49 C.F.R. Part 192. The regulations apply to tasks that are (1) performed on a pipeline facility; (2) part of operations or maintenance; (3) performed as a requirement of Part 192; and (4) affect the operation or integrity of the pipeline. § 192.801.

When the regulation went into effect, PG&E developed an Operator Qualification Committee to determine the covered tasks and design the company's approach. The committee included the OQ coordinator, district and division superintendents, first line supervisors, and engineers. The OQ committee continues to monitor, improve and update the company's OQ program.

The qualification process requires an operator to demonstrate competence through testing or observation by an evaluator, typically a subject matter expert in the field. (P2-149); (P3-10,038). PG&E has currently identified 81 covered tasks. The Company conducts OQ for all the covered tasks that its operations and maintenance staff perform.

PG&E annually reviews employees' OQ status to determine whether they need to update their qualifications. The OQ coordinator shares this information with supervisors at annual OQ program trainings and with individual employees in an annual review. Approximately 2,400 PG&E employees have at least one OQ. As the OQ tasks are fairly narrowly defined, a typical field employee might have 15 OQs (out of the total 81 covered tasks) that fall within his or her job classification.

3. Maintenance Activities to Promote Safety

This subsection discusses several maintenance activities of the kind described in Subpart M of 49 C.F.R. 192.

a. Patrols

The federal regulations require operators to patrol pipelines to observe surface conditions on and adjacent to a transmission line right-of-way. The regulations state that permissible methods of patrolling include walking, driving, flying, or other appropriate means of observing the right-of-way.

Currently, PG&E conducts periodic routine aerial patrols to observe any activity occurring in the vicinity of transmission pipelines. The aerial patrols cover the entire transmission system backbone, Bay Area loop (where flying restrictions allow) and various other segments of the transmission system where feasible. Flights occur at least quarterly, or more often if there is significant activity in a given area. The types of conditions observed and reported are landslides, erosion, damaged markers, construction over pipeline, excavation near the pipeline, blocked access roads, or anything else that appears to threaten the pipeline. If any of these items are observed, the pilot must contact the local maintenance group and provide the location and details for a follow-up on land by PG&E employees.

PG&E also utilizes foot patrols where aerial patrols are not possible. In addition, routine aerial surveillance is supplemented on the ground by the observations of PG&E employees engaged in other system maintenance (e.g., leak surveys).

When a potential issue is identified (i.e., through an aerial or ground patrol or other maintenance activity), the PG&E employee assesses the situation and takes appropriate action. The issue may be resolved by the employee. If there is immediate risk to the pipeline, the employee (i) notifies his or her supervisor (who will contact the fire department or other appropriate first responder if necessary) and (ii) takes appropriate action to reduce the risk. If the issue does not require immediate attention, the supervisor typically will contact the responsible pipeline engineer who, in the first instance, addresses issues such as whether there is an encroachment.

Going back to the earliest years covered by the OII, in 1955, PG&E employed more than 50 men to patrol the 1,500 miles of transmission pipe then in service. The entire transmission system was patrolled by foot monthly and by motor or aerial patrol every week. Ground patrols were conducted by two-men teams—one employee would walk the line and the other would drive nearby in a car equipped with a radio-telephone. These patrols would respond promptly to any identified leaks. (P3-10,040).

In the mid-1960s, PG&E described the Company's patrolling practices to the Commission: "Pipelines in this system are patrolled by air, car, or on foot periodically at intervals commensurate with exposure. In addition to observing for leakage and construction activity, the pipeline right of way and adjacent lands are surveyed for development that may affect public exposure, land surface changes and earth movement due to slides, earthquakes, floods, etc. In addition to scheduled patrolling outlined below, much of our pipeline system is frequently patrolled incidental to other field work." 1966 O&M Report, (P3-10,004). A Standard Practice—460.2-1, Patrolling: Pipelines and Mains—governed the details of the company's transmission line patrolling activities and standardized patrol reporting forms were used. (P3-10,041). At the time, about half of PG&E's pipelines were patrolled by air. (P3-10,005).

b. Leak Survey & Repair

Leak Surveys look for evidence of leaks along the Gas Transmission rights-of-way using approved leak detection instruments. They are conducted on the PG&E's entire Gas Transmission system either once or twice a year, depending on the Class Location. Lines in Class 3 and 4 locations are surveyed semi-annually. Most other transmission pipelines are surveyed on an annual basis.

PG&E has conducted leak surveys on foot with a hand held leak detection device; in a vehicle with a specially installed mobile leak detection device; and via air patrol (vegetation surveys only). PG&E has used portable hydrogen flame ionization instruments or other PG&E-approved combustible gas indicators in foot and mobile surveys. Currently, foot surveys are being used for the entire transmission system except where aerial vegetation surveys are used. A vegetation survey is done by air to identify places where vegetation will not grow due to a potential gas leak in the soil. Vegetation surveys may be utilized only in Class 1 and 2 locations and, if any indication of a gas leak is found, must be followed by a ground survey.

When detected, leaks are graded according to severity. The grade of the leak indicates the type of response that is required. (P2-73). Procedures govern how the repair should be made. (P2-269 to P2-271).

PG&E has engaged in leak surveying, inspection and repair throughout the period covered by the OII. For example, in the mid-1960s PG&E described its leak survey methods to the Commission as including, among other practices, vegetation observation and use of a combustible gas indicator. 1966 O&M study (P3-20,004). The characteristics of the pipe location determined how frequently we surveyed. The Company employed a Standard Practice, 460.21-4, and used a standardized "Leak and/or Shutdown Report" form system-wide to record data on leakage. (P3-10,005). It periodically reported to the Commission on operations activities according to line number, including with regards to pipeline leaks and repairs. (P3-10,042).

c. Valve Maintenance

Federal regulations require that each transmission line valve that might be required during an emergency be inspected and partially operated at least once a calendar year, at intervals not to exceed 15 months. Furthermore, operators must take prompt remedial action to correct any valve found to be inoperable (unless an alternate valve is designated). 49 C.F.R. § 192.745.

PG&E conducts maintenance on power-actuated, remotely controlled valves twice each calendar year. Power-actuated isolation and block valves are inspected, serviced, lubricated, and operated at approximate six-month intervals. Power-actuated regulating valves on standby (i.e., not required for regulation during normal operations) and power-actuated valves used for overpressure protection (monitors) are partially operated and inspected once a month and serviced and lubricated twice each calendar year (at approximate six-month intervals). (P2-139) (P3-10,043)

PG&E has for many years governed the maintenance of its valves through detailed procedures. For example, Standard Practice 805, effective in July 1965, established a procedure for lubricating and maintaining plug valves on transmission lines, replacing prior valve guidance from 1950 and 1959. 1967 Surveillance Report, (P3-10,005). By 1967, a computerized monthly "Preventive Maintenance System Review List" was facilitating the process by alerting maintenance supervisors when it was time to inspect, service or lubricate specific valves. 1967 Surveillance Report (P3-10,005).

TAB 14

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6C
WRITTEN SAFETY RISK ASSESSMENTS AND DOCUMENTS USED TO MAKE PIPE REPLACEMENT DECISIONS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6C
WRITTEN SAFETY RISK ASSESSMENTS AND DOCUMENTS USED TO MAKE PIPE REPLACEMENT DECISIONS

A. Written Safety Risk Assessments and Documents Used to Make Pipeline Replacement Decisions

This Chapter 6C responds to Directives 3.E and 4 of the OII, describing PG&E written safety risk assessments conducted between 1955 and 2010 and the types of documents and information used to make such assessments beginning in 1990. Although many of the practices and policies discussed in Chapters 6A and 6B also concern written safety risk assessments, this Chapter focuses principally on risk assessments designed to inform the decision of whether to replace or retire a particular pipeline or pipe segment. This Chapter also responds to Directives 3.A-3.C in the sense that PG&E's written safety risk assessments constitute actions or procedures to promote the safety of its gas transmission system. Broadly speaking, this Chapter traces the development of PG&E's efforts to assess and improve pipeline safety over the decades. Before 1985, PG&E sought to reduce risk on its gas transmission system principally through pipeline-specific analyses and projects. Beginning in 1985, PG&E consolidated many of these activities into the Gas Pipeline Replacement Program (GPRP), a programmatic initiative approved in PG&E's rate cases, which focused on replacing specific categories of pipeline. Since the late 1990s, PG&E has performed risk assessments on its gas transmission pipelines through a Risk Management Program. That program anticipated the Integrity

Management regulations in 49 C.F.R. Part 192 Subpart O, which were introduced in 2003.

Directive 3.E calls for all written safety risk assessments (defined by the Commission to mean "a PG&E analysis of whether to replace the pipe to promote safety, or whether to conduct additional tests or analyses to confirm the safety integrity of the pipe, or to take other action to promote safety") during the 55-year period at issue. As written, this directive is extremely broad so as to be subject to widely varying interpretations. PG&E has approached Directive 3.E in the following manner. First, for the time period prior to the commencement of its Gas Pipeline Replacement Program (1955-1984), PG&E has conducted a search of its major pipe replacement or retirement projects to locate written safety risk assessments associated with those projects. Second, for the time period that gas transmission pipes were part of its Gas Pipeline Replacement Program (1985-1999), PG&E has focused on replacement work and associated safety risk assessments on a programmatic level rather than a project-specific level. Third, for the time period of its Risk Management Program (1999 to present), PG&E has focused on safety risk assessments on a programmatic level as well as on certain pipeline-specific projects. For all three time periods, PG&E has provided the best information available that reflect written safety risk assessments. Additionally, in attempting to respond broadly to this directive, PG&E has provided a variety of documents that are components of its safety risk assessment practices but are not specifically related to a particular risk assessment. Examples of such documents, discussed in more detail below, include certain in-line inspection and external corrosion direct assessment results, as well as proposed safety and reliability related projects in recent years.

To respond completely to Directive 4 of the OII, in addition to the description and discussion throughout this chapter of documents PG&E used in performing risk assessments, PG&E also appends an index listing, identifying, and describing the kinds of historical documents and other information PG&E used to make its risk assessments. See Appendix 2.

1. Development of Risk Assessment Practices Before 1985

As described more fully in Chapter 1A, throughout the time period covered by Directives 3 and 3E (1955-2010), PG&E expanded its gas transmission system to meet increased gas demand. In the 1950s and

1960s, gas transmission pipelines that had been previously installed were still relatively new, and replacement jobs were infrequent. Indeed, PG&E's first major natural gas transmission line was not installed until 1929. (P3-20001). Thus, in this era, replacements usually occurred in order to increase system capacity or to clear location conflicts with projects by other entities, such as road construction.

Even so, PG&E historically inspected its pipelines and replaced or retired them as needed based on several considerations, including age, reliability and safety.[1] During the 1950s and 1960s, PG&E's safety risk assessment practices consisted of case-by-case analyses of whether to replace or retire a particular transmission pipeline or pipeline segment. Prior to federal pipeline safety regulation, neither PG&E nor the industry had begun to think programmatically about risk assessment as we define it today in connection with Subpart O. However, PG&E did replace pipe based on its conditions, operating history, and design materials.

It is not possible to identify and accurately summarize every pipe replacement job done these many years ago that was or may have been based on a written safety risk assessment. Some jobs may have replaced just a few feet of pipe or a fitting. In gathering data about these early jobs, we have concentrated our efforts on major gas transmission pipeline replacement jobs. These replacement jobs demonstrate that PG&E focused on replacing certain portions of transmission line in order to (1) address design and construction material susceptible to failure, (2) address corrosion risk and (3) better protect the pipeline from the risk of third party damage. PG&E has summarized examples of such replacement activity in Appendix 1.

One of the earliest examples that PG&E has been able to identify of pipe replacement for integrity-related reasons (as opposed to replacements to increase capacity or accommodate third-parties) is its replacement of 560 feet of Line 181 in 1959 due to excessive corrosion damage. See Appendix 1 (P3-27427). In this instance, PG&E discovered corrosion pitting that was

[1] *See* CPUC Decision on 1987 Rate Case. Decision 86-12-095, December 22, 1986. 23 CPUC 2d 149, 198.

sufficiently extensive to warrant the replacement rather than continued operation of a section of the pipeline.

Another early pipe replacement project occurred in 1960 when PG&E replaced approximately 4,580 feet of Line 101. See Appendix 1 (P3-27429). The project was undertaken due to the widening of a nearby highway, to make the pipeline more accessible for maintenance and repair, and in order to address the pipeline's oxy-acetylene welded girth welds. PG&E replaced another approximately 2,840 foot portion of Line 101 in 1960 due to extensive corrosion pitting along the pipe. (P3-27430). In addition, between 1965 and 1966, PG&E conducted hydrostatic pressure tests of eight pipelines and performed one replacement due to class location changes along those pipelines. See 1967 Letter Exchange between PG&E and the CPUC (P3-20002).

In the early 1970s, PG&E increasingly replaced or retired pipe as needed for integrity-related reasons.[2] *See* Appendix 1. In the late 1970s and early 1980s, PG&E began an initiative to replace certain aging transmission pipeline, based on similar criteria later applied under the Company's GPRP. As PG&E told the Commission during discovery in the course of the 1987 General Rate Case:

> Over the past several years, normal replacement of gas transmission lines and distribution mains included a considerable amount of pipe that was within the scope of the Pipeline Replacement Program. (P3-20004).

As discussed above, these replacement projects addressed design and construction material susceptible to failure, corrosion risk and the risk of third party damage. See Appendix 1.

Further, in 1981, PG&E's Department of Engineering Research (DER) drafted a report describing its Gas Pipeline Girth Weld Testing Program under which the DER conducted metallurgical tests of several girth welds on large-diameter segments of Line 105 (since retired) and Line 108 to

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[2] As a precursor to later girth weld testing, in 1979, PG&E completed destructive testing on a 60-foot pipe section of Line 105 to inspect certain oxy-acetylene girth welds. PG&E Report on Bending Test of Oxy-Acetlyne Girth Weld on Line 105 (1979) (P3-20003).

determine the integrity of older joint designs and oxy-acetylene girth welding methods used at the time of installation. This report led to PG&E prioritizing the replacement of certain oxy-acetylene girth welds, bell-bell-chill ring joints and bell-and-spigot joints in its gas transmission system. (P3-20005).

2. Gas Pipeline Replacement Program

In 1985, at a time when there was no regulatory requirement to have a formal risk management program for gas transmission pipe in place, PG&E commenced the GPRP to improve overall gas system safety and reliability. The GPRP was a major program to replace, under a system-wide schedule, deteriorating distribution and transmission gas piping.[3] As originally proposed, the goal of the program was to replace approximately 2,800 miles of pipeline, including approximately 500 miles of transmission pipeline, over a period of roughly 25 years, at an estimated cost of more than $2 billion.[4]

Despite the long-term nature of the GPRP, urgent replacements continued to occur outside the formal program. The GPRP also did not address the rerouting of pipe at the request of others, in which pipeline safety was an added benefit due to the replacement of older pipe with new pipe of higher quality. Instead, the GPRP was primarily aimed at replacing certain types of aging pipe.

The GPRP initially targeted both gas distribution and gas transmission pipe. For distribution, it targeted the replacement of all cast iron main and pre-1931 steel distribution main. For transmission it targeted the replacement of pipe with girth weld types known to experience failure, including segments containing oxy-acetelyne gas welds or unshielded electric arc welds. During the initial years of the GPRP, PG&E prioritized transmission replacement projects only by category of weld and the anticipated difficulty of the project. 1984 GPRP Category Prioritization of Pipelines by County (P3-20006 – P3-20019). However, in 1987, PG&E, in conjunction with consultant engineers from Bechtel Corporation ("Bechtel"), developed a method for prioritizing GPRP pipe segments. The purpose of

[3] CPUC Decision on 1987 Rate Case, 23 CPUC 2d 149 at 198.

[4] CPUC Decision on 1987 Rate Case, 23 CPUC 2d 149 at 198; GPRP 1987 Annual Progress Report at A-1, B-5 (P3-20021).

the prioritization was to identify the pipeline segments posing the greatest risk using a relativistic risk model.[5]

The Commission is well-acquainted with the GPRP. It was part of the 1987 General Rate Case (GRC) and was discussed in the Commission's Decision (D.) 86-12-095 (23 CPUC 2d 149, 198-99). That decision required PG&E to submit progress reports by April 1 of each year (beginning April 1, 1987) summarizing the work accomplished, recorded expenditures and the proposed program and expenditures for the next calendar year.[6] PG&E filed these annual reports from 1987 until 2000 when gas transmission pipe was removed from this program. Copies of PG&E's annual GPRP reports are included as part of this submission. GPRP Annual Progress Reports (1987-2000) (P3-20021 – P3-20034).[7] These reports provide both summary and detailed information on the status of the GPRP and actions taken, including a list of pipe replacements during the year and the resulting reduction in system-wide risk. As detailed in these Annual Reports, from 1985 to 1999 PG&E replaced 343 miles of older transmission pipe as part of the GPRP and succeeded in substantially reducing system-wide risk.

a. Prioritization Methodology

From its inception through 1999 (after which time transmission pipe was no longer included), the GPRP covered pipelines that met certain criteria; as the program evolved over the years in terms of scope (i.e., the types of pipe included in the program), the methodology used for prioritizing pipe replacement also changed.[8]

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5 A "relativistic model" is one that identifies and quantitatively weights major threats and consequences relevant to past pipeline operations. This type of assessment builds on pipeline-specific experience and includes the development of risk models addressing the known threats that have historically impacted pipeline operations.

6 *See* CPUC Decision on 1987 Rate Case, 23 CPUC 2d 149 at 199.

7 Since 2000, GPRP has focused on replacing distribution pipe, while transmission pipe is addressed through PG&E's Risk Management Program, discussed in detail here.

8 PG&E's planned facility replacements under the GPRP (and related expenditures) were subject to change due to unforeseen events such as changing operating conditions, unavailability of permits or rights-of-way, modifications of municipal paving programs, and shifts in priority with further refinement of priority analysis procedures.

At the outset of the GPRP, PG&E conducted an extensive study of its gas transmission system. The primary sources of information for this study were leak repair forms (information gathered during pipeline repairs) and pipeline survey sheets. In the early 1970s, PG&E began to collect and manage leak report form data in records management systems to make the data readily accessible to pipeline engineers. The pipeline survey sheets also provided sources of data. These hand drawn sheets included information on pipeline installation date, job installation project number, wall thickness, diameter, girth weld type, pressure test information, joint efficiency factor, the specified minimum yield strength ("SMYS") and the percent SMYS at both Maximum Allowable Operating Pressure ("MAOP") and Maximum Operating Pressure ("MOP"). Consequence of failure methodology took into account class location and the pipe's proximity to critical structures. Based upon this study, in 1987, PG&E developed, in consultation with Bechtel, a replacement priority analysis program and database which included known information on the status of individual line segments. The priority analysis provided a method for assimilating the information contained in the database and then ranking the segments. It also served as a tool for the planning of replacement projects, subject to other considerations. (P3-20021).

A component of the priority analysis was a risk assignment algorithm, known as the Priority Value. The Priority Value algorithm helped to identify and prioritize gas distribution and gas transmission pipeline segments for replacement. It evaluated (a) pipe age, (b) leak history, (c) girth weld type, (d) strength test history, (e) coating type and condition, (f) longitudinal joint type, (g) circumferential joint type, (h) percent SMYS at both MAOP and MOP, and (i) structure and population proximity. Bechtel Report on GPRP Transmission Line Priority Analysis (1988) (P3-20020).[9] Each pipe's priority value was based on a relative assessment of risk, with the higher priority value having the greater

[9] As part of this filiing, PG&E has produced the Bechtel Report on GPRP Transmission Line Risk Analysis (1985) (P3-20035) and the Bechtel Report on GPRP Transmission Line Priority Analysis (1986) (P3-20036).

estimated risk. The priority values ranged from 0 to 100 for gas transmission pipeline segments.

After the Loma Prieta earthquake, PG&E enhanced the Priority Value algorithm to more accurately assess the risks associated with seismic activity. Initially, the GPRP priority analysis indirectly incorporated seismic considerations by assigning higher values to factors pertaining to leak history, and to types of pipe material, girth welds and joints that were more susceptible to damage caused by ground movement. However, following the 1989 Loma Prieta Earthquake, PG&E expanded the Priority Value algorithm to take potential seismic activity and ground movement directly into account. In 1990, PG&E began to compile geological and geotechnical data to identify geological areas of high liquefaction susceptibility, high slope instability potential, pipeline fault crossings, and locations at which future large earthquakes were anticipated with high likelihood in the next 30 to 50 years within the Company's service territory. Section 3.D.1, below.

Based on this research effort and in further consultation with Bechtel, PG&E revised the transmission priority analysis in 1994 to include a seismic factor based upon (1) the probability of strong ground shaking, (2) the probability of surface faulting, (3) high susceptibility to liquefaction in the area, and (4) high susceptibility to slope instability in the area. Bechtel Review of the Transmission Priority Analysis for the GPRP (1994) at 3-10 – 3-15 (P3-20038).[10]

As a result of these continual refinements to the prioritization methodology for gas pipeline replacement, PG&E continually improved its understanding of the different risks posed to transmission and distribution pipelines.

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10 Also in 1994, PG&E performed an evaluation of the girth weld defects and mechanical properties from segments of Line 109 to determine the susceptibility of the girth welds to fracture from imperfections. The analysis consisted of radiographic testing, tensile and Charpy impact testing, chemical analysis, and macroscopic and microscopic examination of the weld joint. TES Report on the Characterization of PG&E Line 109 Girth Welds (1994) at 1-1 (P3-20039); *see also* EWI Report on the Inspection Criteria for Girth Welds in PG&E Line 109 (1997) at 1 (P3-20040).

In sum, the GPRP was an important element of PG&E's efforts to improve the safety of its gas transmission system. PG&E replaced 343 miles of aging gas transmission pipeline and many more miles of gas distribution pipe under the GPRP. In annual gas reports submitted in the late 1990s through 2007, the USRB lauded the GPRP (and a similar program instituted by Southern California Gas Company).[11] The GPRP was a formal risk assessment program undertaken at a time when such programs were uncommon within the natural gas transmission industry. But in terms of how the gas transmission GPRP evaluated risk and consequence, and the mitigation and prevention strategies it afforded, GPRP was basic when compared to the more comprehensive risk management approach PG&E was soon to adopt.

3. PG&E's Risk Management Program

a. Transition to a Risk Management Model

To supplement and improve operational processes related to managing system risks, PG&E initiated a Gas Transmission Risk Management (RM) Program in 1998. The Risk Management Model provided a more comprehensive way of evaluating risks and consequences, as well as afforded more mitigation and prevention strategies. PG&E took this step while its gas transmission pipelines were still part of the GPRP to promote and evaluate additional safety and reliability projects. (P3-20041).

This development paralleled the industry's transition to a risk management approach. In the 1990s, the natural gas transmission industry and state and federal regulatory agencies, including the Office of Pipeline Safety, began to examine a risk management model of addressing pipeline risk. As W. Kent Muhlbauer wrote in the most recent edition of his highly influential book, Pipeline Risk Management Manual, during the early 1990's, "formal risk assessments of pipelines were fairly rare. To be sure, there were some repair/replace models out there, some maintenance prioritization schemes, and the occasional

[11] CPUC Utilities Safety Branch Natural Gas and Propane Safety Report for 2007 at 11, available at http://docs.cpuc.ca.gov/published/Report/100449.htm.

regulatory approval study, but, generally, those who embarked on a formal process for assessing pipeline risks were doing so for very specific needs and were not following a prescribed methodology."[12]

In 1999, with the concurrence of the USRB, PG&E removed approximately 212 miles of transmission pipeline from the GPRP and placed them under the RM Program. On April 20, 2000, the Chief of the USRB approved PG&E's Gas Transmission Risk Management Program, writing: "The RM program appears to be a good program and it is obvious PG&E has invested time to develop it."[13]

Under the RM program, PG&E utilizes its integrity management risk assessment model to evaluate potential risks on transmission pipeline segments and to analyze those segments to determine the most effective actions to reduce that risk. The integrity risk assessment model offered a number of advantages over the GPRP. Although the GPRP was successful in reducing system-wide risk, only 13 percent of all transmission lines came within its criteria. Even for the pipelines within its purview, the GPRP only considered two mitigation options: replacement or abandonment. Further, in calculating the likelihood of failure ("LOF") for GPRP prioritization purposes, PG&E primarily considered seismic activity and vulnerability due to external corrosion or weld type, but did not consider other risks such as third-party damage and additional factors that could lead to corrosion and other material threats. Likewise, in calculating the possible consequences of failure ("COF") for GPRP prioritizations, PG&E considered pressure, class location, and proximity to other structures, but did not consider impact to system reliability or the environment.

In contrast, PG&E's risk management approach calculates and prioritizes the risk for all gas transmission pipelines in PG&E's system,

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12 W. Kent Muhlbauer, Pipeline Risk Management Manual, Preface to Third Edition (2004).

13 This letter and an account of subsequent conversations between PG&E and the Chief of the Safety Branch were incorporated into the PG&E's 2000 GPRP Annual Progress Report. (P3-20034). In that report, PG&E noted that it had obtained the concurrence of the Safety Branch to transition any remaining transmission pipeline in the GPRP to the Risk Management Program.

and employs several targeted risk reduction activities in addition to replacement and abandonment. The risk management approach incorporated the historical gas transmission pipeline information and knowledge developed through the GPRP, while also including additional factors in determining likelihood of failure, including third-party damage, slope failure, and liquefaction. The consequence of failure determination was expanded to include customer outages, outage duration, and environmental impact, among other considerations.

PG&E supported federal pipeline safety regulation and enhanced its RM Program accordingly. In December 2003, after years of study, PHMSA adopted the transmission pipeline integrity management rules, 49 C.F.R. Part 192, Subpart O ("Subpart O"). Subpart O requires all pipeline operators to implement a Transmission Integrity Management Program (TIMP) to assess and manage the integrity of all gas transmission pipelines in High Consequence Areas (HCAs). PG&E supported the adoption of Subpart O as a way of improving the safety and reliability of gas transmission systems nationwide, and its Risk Management engineers participated in conferences promoting good risk management practices. (P3-20042).

PG&E implemented TIMP through its existing RM Program. Where the RM Program applies to all of PG&E's gas pipeline segments operating at a pressure greater than 60 pounds (psig), TIMP applies to a subset of those segments meeting the definition of a "Transmission line" in 49 C.F.R. Section 192.3. Further, TIMP requires integrity assessments for those segments operating within High Consequence Areas (HCAs), roughly 20 percent of PG&E's existing transmission pipeline segments (or approximately 1,020 miles[14]). In fact, PG&E performs integrity assessments on approximately an additional 500 miles of pipeline segments located outside of HCAs due to pipeline configurations. This percentage changes slightly year by year as new HCAs are created and identified and others no longer meet the criteria to be considered an HCA. However, PG&E continues to apply risk

[14] Pursuant to Method 2 of the HCA designation criteria set forth in 49 C.F.R. § 192.903.

management tools to all of its gas transmission pipelines under the RM Program, not just those located within HCAs.

In December 2005 and May 2010, the USRB conducted two General Order 112-E audits of PG&E's TIMP. No notices of violations resulted from either audit. PG&E appreciates the hard work and dedication of the USRB auditors, and their feedback regarding continued improvement of PG&E's TIMP. As a result of the thoughtful and productive discussions during these audits, PG&E has identified several ways to improve the effectiveness of its TIMP.

After transitioning its gas transmission system from the GPRP to the RM Program, PG&E voluntarily prepared and submitted annual reports to the Commission of its transmission integrity management-related actions and, after the adoption of Subpart O to the Federal Pipeline Safety Program regulations, PG&E voluntarily continued to prepare and submit reports of its TIMP. (P3-20043 – P3-20050).

b. Elements of PG&E's Risk Management Program

The RM Program determines pipeline risk by assessing the probability or likelihood of failure and the consequence of failure. The RM Program calculates risk using the basic equation: Risk = (Likelihood of Failure) * (Consequence of Failure). Likelihood of failure depends on several factors, including pipeline characteristics,[15] such as material strength, diameter and wall thickness, operating pressure, the year the pipe was installed, and vulnerability to third party damage or earthquakes and landslides. Factors relevant to the consequences of failure include population density, the size of the customer base that would be affected by an outage, and environmental impacts. PG&E developed a risk assessment algorithm based on these factors using root cause technical data generated from pipeline failures that had previously occurred across the nation over a ten-year period as well as from input of PG&E subject matter experts.

[15] PG&E Table of Historical Gas Pipe Minimums (2000) (setting forth minimum pipeline characteristics information for use in calculating risk on pipeline characteristics) (P3-20051).

PG&E uses this algorithm to derive risk numbers for every unique segment of gas transmission pipe across nine categories:

- Likelihood of failure due to external corrosion
- Risk due to external corrosion
- Likelihood of failure due to third party damage
- Risk due to third party damage
- Likelihood of failure due to design and materials
- Risk due to design and materials
- Likelihood of failure due to ground motion and other natural forces
- Risk due to ground motion and other natural forces
- Overall Risk

A description of how the risk numbers are determined and assigned is included in the Risk Management Procedures that are discussed in section 3d. below.

Under the RM Program these pipeline segment risk numbers are used to identify and prioritize pipeline segments for potential mitigation projects as part of an effort to reduce overall system risk. For example, since 2001, PG&E's Integrity Management Group has provided PG&E's pipeline engineers (PLEs) an annual risk calculation for each of the approximately 20,000 pipeline segments within the Company's gas transmission system. These annual risk calculations highlight segments for further engineering investigation, monitoring or other long-term follow-up. In order to aid this assessment, since 2003 each annual risk calculation designated a "Top 100" list[16] indicating the particular segments that rank highest in terms of discrete categories: the potential for external corrosion, third-party damage, the physical design and characteristics of the segment, the potential for ground movement, and the overall risk of the segment.[17]

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[16] The 2001 and 2002 annual risk calculation did not designate a Top 100 list. The 2003 annual risk calculation designated a separate Top 100 list which was a separate document from the calculation. (P3-20052). Every year after 2003, the Top 100 was imbedded within each Annual Risk Calculation.

[17] PG&E Annual Risk Calculation Reports (2001-2009) (P3-20053 – P3-20060).

Techniques to reduce pipeline risk under the RM Program include pressure testing, pipeline replacement, in-line inspection, pipeline rehabilitation or recoating, erosion mitigation, direct assessment methodologies, internal corrosion mitigation, pressure reduction, and landowner notification. PG&E has also studied and developed techniques to identify and mitigate special pipeline threats, such as hydrogen stress cracking of hardened areas known as “hard spots,” found in earlier vintage pipeline steels. (P3-20061).

From 2000-2007, PG&E’s Risk Management Program has mitigated transmission pipeline risk on approximately 2,422 total miles by replacing or deactivating pipe; by surveying pipe using ILI; by using External, Internal, or Stress Corrosion Direct Assessments; or by using other Indirect Assessment methods, such as Close Interval Survey, Direct Current Voltage Gradient, or depth surveys to analyze the effectiveness of the cathodic protection systems and the condition of pipeline coating. A summary Table 6C-1 is shown below.

TABLE 6C-1
PACIFIC GAS AND ELECTRIC COMPANY
INTEGRITY MANAGEMENT MILEAGE BY CATEGORY 2000-2007

	Replace	Deactivate	ILI	Other Assessment Methods	Corrosion Surveys	
2000	7	13	34	397	0	
2001	2.7	1.7	92	43.7	0	
2002	6		108	144.7	0	
2003	3.2	1.9	0	84.5	0	
2004	0.7	1.7	35.1	50.4	274.8	
2005	1.4	3.6	197	123	236	
2006	3	1.1	87.5	108	15	
2007	0	0	90	228	26	
Total	24	23	643.6	1179.3	551.8	2421.7

c. PG&E's Use of Risk Calculations

RM Program pipeline segment risk numbers have also been utilized in certain PG&E Project Status Reporting System (PSRS) Reports. The PSRS is a data management tool used by PLEs to track the status of all proposed or ongoing projects managed by the Gas Transmission and Distribution group. When requested by a PLE, PG&E's Integrity Management Group would perform risk calculations to be included in PSRS reports. These risk evaluations would describe the current risk calculation on the pipeline segment and compare that calculation to a projected risk calculation on that segment once the project is complete. As part of this filing, PG&E has provided copies of PSRS records where the Integrity Management Group conducted such a risk evaluation analysis. PG&E has also provided a spreadsheet detailing these particular PSRS projects. PG&E PSRS Records Spreadsheet (P3-21010)[18] and corresponding records of Risk Evaluations (2002-2010) (P3-20062 – P3-20592).[19]

Further, PG&E's RM Program pipeline segment risk numbers are crucial input in the Company's Baseline Integrity Assessment Plans and Long Term Integrity Management Plans. The Baseline Integrity Assessment Plan (BIAP) is PG&E's written plan identifying covered segments, threat identification, risk assessment results and assessment methods and schedules as called for in Subpart O. The BIAP is prepared annually so that changes to these factors are reflected in annual revisions to this plan. (P3-21011 – P3-21018).

At the conclusion of each pipeline integrity assessment, a Long Term Integrity Management Plan (LTIMP) is developed to establish reassessment intervals and prevention and mitigation plans. The

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18 Please note, PG&E's PSRS database lists approximately 1,800 projects designated as a safety and reliability or integrity management related projects; PG&E has not produced PSRS data on all 1,800.

19 PG&E also utilized its risk calculations prior to 2004 in its Risk Mitigation Plans which were used as a tool to evaluate possible risk mitigation effort on certain pipeline segments. (P3-20593 – P3-20627). Likewise, from 2004 through 2006, PG&E relied upon segment risk numbers in order to generate Integrity Management Area Reports which were used to analyze threats within particular HCAs. (P3-20628 – P3-21009).

document includes data considered, how the data was integrated, analysis and recommendations. PG&E Long Term Integrity Management Plan Reports (P3-21019 – P3-21040); *see also* RMP 11 Section 6.0, p. 30 (P2 393). PG&E is providing copies of the results of External Corrosion Direct Assessment (ECDAs), Internal Corrosion Direct Assessment (ICDAs), Stress Corrosion Cracking Direct Assessment (SCCDAs), and In-Line Inspection (ILIs) the Company has conducted under its RM Program with this report, as well as the LTIMPs described above. PG&E External Corrosion Direct Assessment Reports (P3-21042 – P3-27178); PG&E Internal Corrosion Direct Assessment Reports (P3-21042 - P3-27178; P3-27249 - P3-27322); PG&E Stress Corrosion Direct Assessment Reports (P3-27235 - P3-27248); PG&E In-Line Inspection Reports (P3-27323 – P3-27390). PG&E has provided the LTIMP for each completed ECDA and ILI. When the Company has not completed an LTIMP for a project, PG&E has provided a copy of its ECDA, ICDA, SCCDA, or ILI final report.

In addition to the integrity assessments discussed above, PG&E's Integrity Management group also tracks leaks in HCAs and in other locations in order to study the root cause of those leaks. This root cause analysis helps to inform the Company's weighting of threats to the integrity of its pipelines which, in turn, is utilized to improve risk calculations under the RM Program. PG&E Leak Root Cause Analysis Spreadsheet (P3-21041).

Likewise, PG&E has also conducted significant evaluation and analysis of the threats to the integrity of its pipelines and the risks associated with those threats on particular transmission pipelines, which enhances the Company's understanding of the total risk to its transmission system. For example, as part of these pipeline-specific studies, PG&E has analyzed stress corrosion cracking on Lines 300A, 300B, and 172A (J.E. Marr Report on the Stress Corrosion Cracking Investigative Program on PG&E Lines 300A and B (1996) at 1-3, 17 (P3-27391); TES Report on the Inspection of Selected Sites on PG&E Lines 300 A and B for Corrosion, Pitting, and Stress Corrosion Cracking

(1997) at 1, 8 (P3-27392);[20] SIA Report on the Metallurgical & Fitness for Service Analysis of PG&E Line 172A (2002) at 3, 12, 15) (P3-27396); a leaking ERW seam on Line 21E (*See* SIA Report on the Evaluation of Leaking ERW Seam on Line 21E (2006) at 2) (P3-27397); and the risk of third party damage on Line 57C (Kiefner Report on the Resistance of PG&E Line L-57C to Third-Party Mechanical Damage (2006) at 1) (P3-27398). The results of these analyses have been used by PG&E to generate inputs to an analysis of the likelihood of failure of similar risks across PG&E's gas transmission system.

d. RM Program Documents

PG&E memorializes the required processes for calculating transmission pipeline risk in the Risk Management Procedures (RMPs). (P2-342 – P2-399). With the advent of TIMP rules, the scope of the RMPs was broadened to address general integrity management program implementation, HCA identification, assessment methods and the PG&E public awareness program. Table 6C-2 shows the current gas transmission-related RMPs:

TABLE 6C-2
PACIFIC GAS AND ELECTRIC COMPANY
TRANSMISSION-RELATED RISK MANAGEMENT PROCEDURES

RMP-01	Risk Management
RMP-02	External Corrosion Threat Algorithm
RMP-03	Third Party Threat Algorithm
RMP-04	Ground Movement Threat Algorithm
RMP-05	Design/Materials Threat Algorithm
RMP-06	Gas Transmission Integrity Management Program
RMP-08	Identification, Location and Documentation of High Consequence Areas (HCA's)

[20] *See also* TES Report on the External Inspection of PG&E Line 300A (1998) at 1 (P3-27393); SIA Report on Line 300A Metallurgical and Fitness For Service Analysis of Girth Welds (2002) at 2 (P3-27394); PG&E Line 300A Wrinkle Bend Burst Test Report (2004) at 1 (P3-27395).

RMP-09	Procedure for External Corrosion Direct Assessment
RMP-10	Procedure for Dry Gas Internal Corrosion Direct Assessment
RMP-11	Procedure for In-Line Inspections
RMP-12	Pipeline Public Awareness Plan
RMP-13	Procedure for Stress Corrosion Cracking Direct Assessment

PG&E first issued RMPs 01 through 05 in 2001. RMP-01 provides an overview of the procedures that govern the risk management process. (P2-347). It describes the different factors used to assess risk, such as facility design attributes, existing conditions, potential threats and failure consequences. It also explains how the factors are weighted. RMPs 01 and 06 (discussed below) provide the overall risk management process and procedures, while the other RMPs (02 through 05 and 08 through 12) include guidelines for determining algorithms for calculating risks, procedures for assessment, data collection methods and tools, and information about the Pipeline Public Safety Plan.

RMPs 02 through 05 each address specific categories of potential threats. They help engineers craft algorithms to determine the likelihood of failure and the risk posed by categories of pipeline threats. Each RMP includes factors to be considered to determine the likelihood of failure of the pipeline due to the threat and a description of how the factors are to be weighted. For example, RMP-02 identifies thirteen factors to be considered, including conditions of the pipe and results of testing. (P2-353). Points are weighted to determine the likelihood of failure due to each factor and the relative severity of failure. The points are then added together for a total score. The score quantifies the relative risk.

In 2004, PG&E added RMP-06 to address provisions of the Transmission Integrity Management Program (TIMP) rules that were then coming into effect. RMP-06 sets out procedures to identify, assess and manage the integrity of gas transmission pipelines in High Consequence Areas (HCAs). (P2-376). RMP-06 outlines the process and requirements for scheduling and updating Baseline Integrity Assessment Plans (BIAP) and the planned schedule for the assessment of all transmission lines within HCAs. It includes procedures for assessment, repairs, management of changes, record keeping, quality assurance, and communication plans.

RMPs 08 through 13 expand on the procedures addressed more generally in RMP-06. RMP-08 details procedures used to identify, locate, document and retain records for HCAs. (P2-384). RMPs-09, 10, 11, and 13 provide further details regarding these tools and methods, namely, the procedures for: external corrosion direct assessment, dry gas internal corrosion direct assessment, in-line inspections, and stress corrosion cracking direct assessment.

RMP 12 contains the elements of the Pipeline Public Awareness Program. The goal of the program is to inform the public of the presence of PG&E's gas pipelines. A more informed public that understands the safe and proper ways to work around pipeline facilities and the required actions prior to excavation will contribute to preventing or reducing damage to pipelines. The program also aims to help the public to understand the steps that should be taken to prevent and respond to pipeline emergencies.

What have been described so far are Risk Management procedures. Risk Management Instructions (RMIs) describe acceptable methods for carrying out specific requirements of the RMPs. (P3-27399 – P3-27415). Table 6C-3 shows the current RMIs relating to transmission piping.

TABLE 6C-3
PACIFIC GAS AND ELECTRIC COMPANY
TRANSMISSION-RELATED RISK MANAGEMENT INSTRUCTIONS

RMI-01	HCA Identification in Support of Annual Systemwide Risk Calculations
RMI-02	GIS Data Queries in Support of Systemwide Risk Calculations
RMI-03	Annual Systemwide Risk Calculations
RMI-04	Gas Transmission Earthquake Plan and Response Procedures
RMI-04A	Gas Transmission Rainfall Plan and Response Instruction
RMI-05	Station HCA Analysis
RMI-06	Stability Determination of Seam Related Manufacturing Threats
RMI-07	Assessment Mileage Recording Process

The first three RMIs instruct on how to perform the annual system wide risk calculations required by RMP-06. RMI-01 provides guidelines for performing GIS data queries in support of the annual system wide risk calculations when a review is required for changes to land use information. RMI-01 also explains the Annual System-wide HCA identification review process. RMI-02 instructs on how to perform GIS data queries in support of the annual system wide risk calculations, including how to capture and export data to a spreadsheet to be used to perform the system wide risk calculations. RMI-03 provides guidelines for performing annual system wide risk calculations using the spreadsheet of the integrated threat and consequence information gathered under RMI-02.

RMI-04 and RMI-04A address emergency and operational risks. RMI-04 describes PG&E's use of GIS-based products to enhance emergency response following a significant earthquake in the San Francisco Bay Area. RMI-04 describes the Gas Transmission Earthquake plan, including eight Bay Area earthquake scenarios for the major faults. It also describes the gas transmission pipeline earthquake risks and provides information about the vulnerable pipeline segments and stations. The instruction sets forth earthquake response procedures and post-earthquake initial damage evaluation guidelines. RMI-04A provides instruction for mitigating any weather-related ground movement threats to PG&E's pipelines by setting out a methodology for identifying rainstorm critical pipeline segments, describing the rainfall response, and describing the post-rainfall initial damage evaluation guidelines.

RMI-05 provides guidelines for performing GIS data queries in support of Station HCA identification and its assessment. The instruction walks through the steps for identifying HCA piping in stations shown in GIS and documenting the results for assessment. RMI-06 maps out a process for analyzing the stability of seam-related manufacturing threats covered under 49 C.F.R. § 192.917(e)(3) and (3)(4) and RMP-06. (P3-27411).

The Direct Assessment (DA) and In Line Inspection (ILI) teams assess pipeline in a variety of stages. RMI-07 instructs on how to capture the dates of these stages and maintain an Assessment Database reflecting those assessment dates that can be queried for mileage. (P3-27415). The intention is to maintain a one-to-one relationship between this assessment data and the GIS Pipeline Data, allowing the pipeline data to serve as the authority on segment footage and HCA status, and the Assessment Database to serve as the authority on assessment dates and exceptions to those scheduled dates, as well as a process for authorizing such exceptions. This instruction also provides that total mileage will be reported monthly and semi-annually.

4. Other Important Risk Assessment Activities

a. Enterprise Risk Management

Enterprise Risk Management (ERM) is a process for managing PG&E's key enterprise risks. (P3-27416; P3-27417). The risks covered by the ERM program are selected through an annual process that identifies those risks whose consequences are potentially significant in the areas of finance, reputation, and/or health and safety of employees, customers, and/or the general public. The ERM program allows the Company to manage those key risks proactively, thus reducing their probability of occurrence and/or the severity of their potential consequences.

Since 2007, PG&E has identified the risk to "System Safety" as one of its top enterprise risks. The definition of the "System Safety" risk is: a single significant event occurring in a high density area, or of multiple recurring significant events within a short-medium term period independent of geography, resulting in fatalities and/or severe injuries. The scope of this risk is limited to system events as defined above that intersect with particular types of transmission and distribution equipment that have the capability of explosion and fire, resulting in fatalities and/or severe injuries. Through the ERM risk analysis process, PG&E has identified various risk drivers related to the gas transmission and distribution system such as corrosion, improper operation, and inadequate maintenance standards and procedures, and has taken mitigative actions to address these risks.

b. Addressing Risk From Ground Movement: Seismic Activity and Landslides

PG&E's service territory includes areas of frequent and pervasive seismic activity. The service territory's diverse topography raises the pipeline safety risks associated with landslides. The federal regulations address ground movement risk under Integrity Management at Subpart O. RMI-04 represents PG&E's approach to this risk today. *See* RMI-04, Rev. 0 (P3-27406).

PG&E formed a Geosciences Department in the mid-1980s. The department includes seismologists, geologists, geotechnical engineers, and structural engineers. One of its responsibilities is to better enable PLEs to ensure pipeline designs take seismic features into account.

After the Loma Prieta earthquake in 1989, the Geosciences Department performed a comprehensive seismic review of PG&E's pipeline systems and risks to those pipelines. PG&E Report on

Reducing Gas and Electric Vulnerability by the Year 2000 (1990) (P3-20037).[21] This review extended even to looking at control room equipment to make sure it was properly anchored. As the company implemented the GIS system in the later 1990s, the power of the department to undertake sophisticated analyses greatly expanded. *See, e.g.*, Letter to PG&E Geosciences Dept. from William Lettis & Associates, Inc., November 9, 2005 (P3-27422). Through the use of the extensive seismic information provided by the U.S. Geological Services in combination with the geographic information available in GIS, the department was able to begin addressing complex tasks such as developing a detailed and specific fault crossings list for all of the company's pipe segments. The implementation of the GIS technology allowed the department to start making system-wide analyses where they were formerly restricted to case-by-case analyses.

One by-product of the integration of GIS and comprehensive seismic information has been PG&E's Gas Transmission Earthquake Plan and Response Procedure, RMI-04. *See* RMI-04, Rev. 0 (P3-27406). The plan was introduced in 2006, and the introduction was accompanied by training in the program for personnel within both the gas and electric systems. The procedure includes the "DASH" program, developed by the Geosciences Department by taking advantage of the department's analytical capabilities. The program provides detailed scenarios and annual updates based on eight possible Bay Area earthquakes. These scenarios include "Shake Maps" and lists of high risk gas pipes and stations associated with that potential earthquake. The Geosciences Department quantifies the relative risk of the different scenarios using an earthquake risk value algorithm that factors in fault crossings, liquefaction, slope stability, pipe age, HCA designations, and the Shake Map. The scenarios provide useful information for operations

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[21] PG&E Seismic Vulnerability Assessment of the Gas Supply Business Unit System (P3-27420); PG&E Seismic Hazard Evaluation of Lines 101, 109, and 132 (1991) (P3-27419); PG&E Seismic Vulnerability Assessment of Pacific Gas and Electric Company Gas Transmission System (1993) (P3-27420); EQE Report on Analysis of Proposed PG&E Pipeline Configurations Potentially Impacted by a Repeat of the 1906 San Francisco Earthquake (1995) (P3-27421).

and maintenance supervisors prior to a quake. The DASH program also automatically calculates the risk to pipeline segments after an actual earthquake and electronically sends the information to maintenance supervisors. That report specifies what segments were at risk and thus helps personnel in the field prioritize their investigations.

PG&E pipelines are also threatened by landslides, especially following periods of heavy rainfall. The Geosciences Department has developed another sophisticated mitigation tool to address that threat, called the Rainfall Landslide Forecast. The program is included in RMI-04A. The Rainfall Landslide Forecast integrates GIS data and rainfall data to determine risk levels. The program factors in annual rainfall and daily rainfall to assess whether particular pipeline segment locations, based on their soil and slope attributes, are at risk of a landslide. That information is then automatically emailed to the maintenance supervisors if the risk reaches a certain threshold so that they can take preparatory or responsive action as needed.

c. Corrosion Control

Corrosion is one of the more prominent threats to a pipeline. As background, PG&E has been using cathodic protection on some of its transmission lines since 1929. PG&E Applied Technology Services, ATS 2010 Annual Report, March 2011 (inside cover) (P3-27423). Since 2008, PG&E has trained personnel in corrosion control at its enhanced Employee Qualification Center in Livermore, California. As described in Chapter 6B, the Livermore facility provides hands-on training on cathodic protection.

Subpart I of the 1970 federal regulations addressed corrosion control. It went beyond the former GO 112 B requirements by requiring that pipelines have coating and cathodic protection and electrical isolation to protect against external corrosion and that the cathodic protection system be monitored. It also required efforts to mitigate internal corrosion. The Subpart required maintenance of records related to the corrosion control requirements. In 2005, OPS amended Subpart I to address the requirements for using direct assessment for corrosion monitoring. PG&E'S Gas Standard O-16 outlines the requirements for corrosion control of PG&E's gas pipelines. (P2-19 – P2-26).

Effective and constant cathodic protection is fundamental to minimizing the risk of pipes developing leaks. But cathodic protection is only effective if the rectifiers, when used, do not break down and the protective current is not interrupted. Regulations require periodic assessments by operators to perform pipe-to-soil tests and to confirm that the rectifier is operating correctly. The regulations require pipe-to-soil testing once a year and rectifier checks six times per year.

A properly functioning rectifier does not equate to a fully functioning cathodic protection system. Pipe-to-soil potential measurements are a direct indication of the level of cathodic protection on a system whereas rectifier current output is an indirect measure. In other words, a system could be "down" (due to a contact or other interference) even though the rectifier is functioning properly. This is a concern because the Cathodic Protection Area could be inadequately protected for up to 18 months– until the next required pipe-to-soil reading. Since 1996, PG&E has therefore taken the step of requesting that the Commission grant a waiver to reverse the cathodic protection monitoring requirements, so that it may test the pipe-to-soil potential of local transmission lines and distribution mains six times a year and check its rectifiers once a year. PG&E Exemption from Rectifier Inspection Resolution No. SU-39 (P3-27506).

In 2008, PG&E began installing remote monitors on all its transmission rectifiers. In addition to providing real time data, the remote sensors provide valuable maintenance and reliability information. The remote monitors allow PG&E to receive information daily about whether the cathodic protection on a particular part of the transmission line is functioning or whether there has been an interruption that requires investigation and repair.[22]

[22] Pipeline safety regulations require an operator to check that a rectifier is working every two months.

APPENDIX 1

Pre- GPRP Projects 1970-1985

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27425	118626	March 1952	2150	PG&E replaced pipe to resolve location conflicts with proposed freeway work, and due to deterioration caused by corrosion.
P3-27426	136865	1956	8080	PG&E removed, reconditioned, and reinstalled pipe to resolve location conflicts with proposed freeway work.
P3-27427	141839	May 1959	560	PG&E replaced pipe due to deterioration caused by corrosion.
P3-27428	145481	May 1959	401	PG&E replaced pipe due to deterioration caused by corrosion.
P3-27429	145815	June 1960	4580	PG&E replaced pipe, installed in 1929, to clear a construction conflict and to remove older vintage pipe from service in a confined location.
P3-27430	149403	November 1960	2840	PG&E replaced pipe installed in 1929 due to deterioration caused by corrosion, leak repair history, and generally due to girth weld vintage.
P3-27424	3167	July 1969	29506	PG&E replaced pipe due to deterioration caused by corrosion and to increase capacity.
P3-27431	173232	October 1969	1070	PG&E relocated and lowered a section of pipeline due to significant erosion at a crossing of the Salinas River in San Luis Obispo County. Pipeline had been uncovered and exposed during floods.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27435	173930	February 1970	815	Replaced pipe installed in 1924 because of deterioration caused by corrosion.
P3-27436	176350	May 1971	880	PG&E replaced a section of pipe and retested another section to comply with new federal safety standards relative to the operating pressure and class location changes. PG&E also replaced 1,270 feet of Line 300B.
P3-27437	176351	March 1971	2192	PG&E replaced a section of pipe to comply with new federal safety standards relative to the operating pressure and class location changes.
P3-27438	176702	July 1971	2512	PG&E replaced pipe installed in 1929 due to deterioration caused by corrosion, existing leak indications and leak repair history, and generally due to girth weld vintage.
P3-27432	3294	May 1972	41395	PG&E replaced pipe to increase capacity as part of a longer term objective, and because of deterioration caused by corrosion.
P3-27439	178515	May 1972	2531	PG&E replaced a section of pipe and retested another section to comply with new federal safety standards relative to the operating pressure and class location changes. PG&E also replaced 2,417 feet of Line 300B.
P3-27440	180565	April 1973	5598	PG&E replaced pipe installed between 1929 and 1958 due to concerns over vintage girth welds (on the 1929 pipe), constrained access and close proximity to pending development, excessive cover which decreased access for repair, and development directly over the pipeline.
P3-27433	3332	June 1973	25023	PG&E replaced pipe to increase capacity as part of a longer term objective, and because of deterioration caused by corrosion.
P3-27441	180666	August 1973	776	PG&E replaced pipe installed in 1936 (with bell-bell-chill-ring joints) due to vintage, close proximity to high density residential housing, and limited access for future maintenance.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27442	182809	March 1974	1205	PG&E replaced 20" oxy-acetylene welded pipe installed in 1929 due to concerns regarding construction vintage to be subjected to increased exposure to traffic loading as a result of changes to the street, and to resolve location conflicts with street construction work.
P3-27443	183227	1974	570	PG&E relocated Lines 109 (installed 570 feet) and 132 (installed 610 feet) out of unstable hillside locations due to threat of damage caused by landslides.
P3-27444	183315	1974	702	PG&E replaced a section of pipe to comply with new federal safety standards relative to the operating pressure and class location changes. PG&E also replaced 865 feet of Line 300B.
P3-27434	3351	May 1974	14499	PG&E replaced pipe because of deterioration caused by corrosion, and out of concern over the integrity of expansion joints.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27480	191255	unknown	40	PG&E conducted hydrostatic tests on pipe to restore compliance with more stringent requirements driven by a change in class location of the surrounding area.
P3-27484	1915651	unknown	19	PG&E conducted hydrostatic tests on pipe to restore compliance with more stringent requirements driven by a change in class location.
P3-27445	SP3350	March 1974	1682	PG&E replaced pipe to clear a location conflict with highway construction, and to provide protection from corrosion.
P3-27455	183588	August 1974	3585	PG&E replaced pipe because of deterioration caused by corrosion, and to resolve access constraints which would have hampered future maintenance and repair.
P3-27456	183649	September 1974	3356	PG&E replaced pipe installed in 1929 due to deterioration caused by corrosion, inability to provide protection in compliance with 49 CFR § 192, and to meet more stringent requirements associated with an impending class location change.
P3-27447	3372	February 1975	9500	PG&E replaced pipe installed in 1930 to clear a location conflict with future development, and to address deterioration caused by corrosion.
P3-27457	184419	May 1975	336	PG&E replaced pipe due to deterioration caused by corrosion and due to concerns over the integrity of joints.
P3-27446	3352	September 1975	3550	PG&E replaced pipe because of deterioration caused by corrosion, and to relocate to eliminate the threat of damage due to unstable soil.
P3-27448	3419	October 1975	16852	PG&E replaced pipe that was not possible to protect from corrosion, so that protection and compliance with 49 CFR § 192 cathodic protection requirements could be achieved.
P3-27449	3420	November 1975	700	PG&E lowered pipe to restore adequate cover to protect from the threat of third-party farming operation damage.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27451	3425	December 1975	32133	PG&E replaced pipe that was not possible to protect from corrosion, so that protection and compliance with 49 CFR § 192 cathodic protection requirements could be achieved.
P3-27460	185927	1976	3169	PG&E replaced pipe to clear location conflicts and proximity issues with planned street construction, and to address integrity concerns with joints as well as concerns over proximity to residential structures.
P3-27464	187189	1976	4855	PG&E replaced and relocated pipe installed in 1929 to increase capacity, and due to concerns over close proximity to dense population, excessively constrained access that would hamper repair and inevitable future replacement, and deterioration caused by corrosion.
P3-27458	185595	June 1976	75820.8	PG&E replaced pipe installed in 1946 due to increased concerns over exposure to third-party damage due to shallow cover and damage history, and because of deterioration caused by corrosion.
P3-27459	185596	June 1976	2208	PG&E replaced and relocated pipe installed in 1929 due to concerns over girth weld vintage, close proximity to dense population, and excessive constraints on access which would hamper future maintenance and repair.
P3-27462	186747	1977	100	PG&E replaced and relocated pipe to clear a location conflict with other construction, and due to concerns over the integrity of girth welds, certain other joints, and the inability to protect from corrosion.
P3-27471	188378	1977	1700	PG&E replaced pipe as part of its program to replace large diameter pipe containing oxy-acetylene girth welds.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27450	3423	January 1977	3510	PG&E replaced pipe which was not possible to protect from corrosion, so that protection and compliance with 49 CFR § 192 cathodic protection requirements could be achieved.
P3-27461	186632	March 1977	27456	PG&E replaced and relocated pipe installed in 1929-30 due to deterioration caused by corrosion, inability to provide cathodic protection, concerns over exposure to third -party damage due to shallow cover and damage history, concern over close proximity to future development, and general concern over girth weld vintage.
P3-27503	4313318	May 1977	27456	PG&E performed strength tests and x-ray inspections of gas dehydration vessels to confirm the integrity.
P3-27463	187052	May 1977	26400	PG&E tested pipe to comply with federal safety standards relative to the operating pressure and class location changes.
P3-27465	187249	September 1977	3600	PG&E replaced and relocated pipe installed in 1930 due to deterioration caused by corrosion, concerns over certain joints, concern over close proximity to population, excessive constraints on access which would hamper future maintenance and repair, and general concern over girth weld vintage, and to increase capacity.
P3-27466	188030	April 1978	1171	PG&E replaced river crossing pipe due to exposure caused by water flow erosion, and concerns regarding the threat of damage due to continued erosion and flow.
P3-27468	188300	April 1978	2489	PG&E replaced and relocated pipe in order to eliminate the threat of damage due to location in an area experiencing landslides.
P3-27467	188291	May 1978	2270	PG&E replaced pipe to clear location conflicts with planned street reconstruction, and due to concerns over 1930 vintage girth welds, deterioration caused by corrosion, and proximity to existing population and expected future high-density residential development.
P3-27469	188367	May 1978	1740	PG&E replaced the pipe to clear conflicts, and in lieu of

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
				continued repair.
P3-27470	188371	May 1978	700	PG&E lowered pipe to eliminate the threat of future damage from high water flow, and replaced girth welds that were found to lack satisfactory integrity.
P3-27472	188445	June 1978	6440	PG&E replaced pipe installed in 1930 due to concerns over vintage oxy-acetylene girth welds and concerns regarding the integrity of certain joint types.
P3-27473	188446	June 1978	2795	PG&E replaced and relocated pipe installed in 1929 to clear location conflicts associated with street reconstruction, and due to concerns over vintage oxy-acetylene girth welds.
P3-27474	188455	June 1978	28	PG&E conducted a hydrostatic strength test of a pipeline section installed in 1949, as part of a program to confirm integrity by strength testing transmission lines in class 3 and 4 areas operating above 20% SMYS.
P3-27475	188999	October 1978	205	PG&E replaced and relocated a main line valve that was inoperable, to restore correct function and correct transmission pipeline flow characteristics.
P3-27454	4922C	1979	53	PG&E replaced the pipe to comply with more stringent requirements resulting from a class change in the surrounding area.
P3-27476	189650	March 1979	1980	PG&E replaced 1929 pipe due to concerns over vintage pipe and girth welds in close proximity to class 3 and possible class 4 development, and concerns over excessive constraints on access after area development which would hamper inevitable replacement.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27477 P3-27478	190242	August 1979	500	The original pipe's repair history and its proximity to encroaching residential development necessitated replacement with a more durable pipe. PG&E also lowered and relocated the pipe for added safety.
P3-27479	190335	August 1979	220	PG&E replaced 1930 pipe due to exposure and deterioration and caused by creek bed erosion.
P3-27483	414847	May 1980	76	PG&E replaced pipe in order to relieve stress on the line where it crossed over sewer structures.
P3-27481	191396	July 1980	4677	PG&E replaced pipe installed in 1932, as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density, and due to concerns over pipe vintage.
P3-27482	191519	August 1980	7359	PG&E replaced pipe installed in 1930, as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density, and due to concerns regarding pipe vintage, integrity of certain joints, excessively constrained access for maintenance, repair and future replacement, and deterioration caused by corrosion.
P3-27488	1924539	1981	3500	PG&E replaced pipe installed in 1932 as part of its program to replace and/or test transmission lines in close proximity to population, and due to concerns over integrity due to girth weld and pipe vintage, inability to adequately protect from corrosion, and exposure to third-party damage due to inadequate cover.
P3-27485	1919141	March 1981	9310	PG&E replaced pipe installed in 1936, as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density, and due to concerns over pipe vintage, deterioration caused by corrosion, and excessively constrained access for future repair and inevitable replacement.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27486	1920263	April 1981	1087	PG&E replaced pipe installed in 1929 as part of its program to replace and/or test transmission lines in close proximity to population, and due to concerns over integrity due to girth weld and pipe vintage, and inability to adequately protect from corrosion.
P3-27487	1922715	August 1981	1081	PG&E replaced pipe installed in 1944 due to inadequate clearance from planned street construction work, and as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density.
P3-27489	1927243	March 1982	765	PG&E replaced pipe due to a location conflict with a creek-widening project, as part of its program to replace large diameter pipe containing oxy-acetylene and/or bell-bell-chill-ring girth welds in areas of high population density, and due to concern over the integrity of vintage pipe and the inability to provide protection from corrosion.
P3-27490	1927466	April 1982	3620	PG&E replaced pipe as part of its program to replace large diameter pipe containing oxy-acetylene and/or bell-bell-chill-ring girth welds in areas of high population density, and due to concern over the integrity of vintage pipe, certain joints and fittings and the inability to provide protection from corrosion.
P3-27491	1928159	June 1982	2115	PG&E replaced and relocated pipe due to excessive access constrains as a result of residential development, which hampered maintenance and repair, and due to the concern over the ease of a gas leak migrating to inhabitable structures.
P3-27492	1928555	July 1982	10400	PG&E reconditioned and reinstalled pipe to relieve excessive stresses resulting from the presence of a highway crossing, and due to deterioration caused by corrosion.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27498	1935162	1983	9100	PG&E relocated pipe out of an unstable hillside location due to the threat of damage caused by landslides.
P3-27493	1932441	February 1983	1660	PG&E replaced pipe installed in 1944 due to location conflict with planned street construction work, and as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density.
P3-27502	4278206	April 1983	1630	PG&E replaced pipe as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density, and due to the inability to provide protection from corrosion.
P3-27452 P3-27453	3702R	August 1983	3150	PG&E replaced pipe to eliminate the threat of damage due to landslides.
P3-27496	1934702	October 1983	2772	PG&E replaced river crossing pipe installed in 1930, due to concerns and experience regarding the integrity of girth welds and leak history.
P3-27495	1934025	December 1983	1133	PG&E replaced 22" pipe with 36" pipe due to class location changes.
P3-27494	1932813	1984	22600	PG&E replaced pipe installed in 1932, as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density, due to concerns over the threat of third-party damage because of inadequate cover, and due to excessively constrained access for maintenance, repair, and inevitable future replacement.

Attachment Number	Job No.	Date Commenced	Approx. Footage	Description of Replacement Project
P3-27500	1937937	1984	1365	PG&E replaced pipe, as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density, and due to concerns over the integrity of vintage pipe and the inability to provide protection from corrosion.
P3-27499	1937176	March 1984	18500	PG&E replaced pipe installed in 1930, as part of its program to replace large diameter pipe containing oxy-acetylene and bell-bell-chill-ring girth welds in areas of high population density, and due to concerns over the integrity of vintage pipe and certain joints, and the inability to provide protection from corrosion.
P3-27504	4361622	March 1984	325	PG&E replaced due to deterioration caused by corrosion.
P3-27501	1938166	May 1984	6976	PG&E replaced 1929 pipe to increase capacity, and due to concerns regarding the integrity of oxy-acetylene girth welds, the integrity of vintage of pipe, the threat of third-party damage as a result of inadequate cover, and the inability to provide protection from corrosion.
P3-27505	4418497	July 1984	567	PG&E relocated the pipeline because of severe hillside erosion.
P3-27497	1935089	July 1984	5200	PG&E replaced river crossing pipe due to exposure caused by water flow erosion, and concerns regarding the threat of damage due to continued erosion and flow.

APPENDIX 2

RESPONSE TO CPUC DIRECTIVE 4 – LIST, IDENTIFY AND DESCRIBE RISK ASSESSMENT DOCUMENTS

In OII Directive 4, the Commission directs PG&E to "list and identify, and describe, the types of historical documents and other information that PG&E used to make its assessments (e.g. as built documents, operational pressures)." In Chapter 6C, PG&E has described the major studies and analyses it has and continues to utilize in order to make safety risk assessments across its transmission system. In addition, PG&E sets forth below the types of documents and information it relied or continues to rely upon to make those safety risk assessments:

TABLE 6C-4
PACIFIC GAS AND ELECTRIC COMPANY
RESPONSE TO CPUC DIRECTIVE 4

Document Category	Purpose of Document	Period
As Built Documents	Used to determine pipe characteristics in order to conduct safety risk assessments	All Periods
Operational Pressures	Used to determine pipe characteristics in order to conduct safety risk assessments	All Periods
Leak Repair Forms ("A Forms")	Used to determine pipe characteristics in order to conduct safety risk assessments	All Periods
Pipeline Survey Sheets	Used to determine pipe characteristics in order to conduct safety risk assessments	All Periods
Class Location Designations	Used to determine pipe characteristics in order to conduct safety risk assessments	All Periods
Additional Pipeline Design Docume	Used to determine pipe characteristics in order to conduct safety risk assessments	All Periods
Girth Weld Testing and Analysis	Used to determine pipe characteristics in order to conduct	All Periods

	safety risk assessments	
Seismic Studies and Analysis	Used to determine the risk of ground movement as part of safety risk assessments	GPRP, RM Program
External Corrosion Studies and Analysis	Used to determine the risk of external corrosion as part of safety risk assessments	GPRP, RM Program
GPRP Priority Analysis Reports	Used to develop and update PG&E's risk assessment priority analysis as part of the GPRP	GPRP
Geographic Information System Database	Used to determine pipe characteristics in order to conduct safety risk assessments	RM Program
Risk Management Procedures 1-13	Used to guide the different factors used to assess risk, such as facility design attributes, existing conditions, potential threats and failure consequences; as well as explain how the factors are weighted.	RM Program
Historical Gas Minimum Study	Used to determine pipe characteristics in order to conduct safety risk assessments	RM Program
Hydrogen Stress Cracking Study	Used to determine pipe characteristics in order to conduct safety risk assessments	RM Program
High Consequence Area Designation Annual Reports	Used to determine and update the scope of PG&E safety risk assessments in High Consequence Areas	RM Program
Baseline Integrity Assessment Plans	Used to identify threats and risk assessment results in order to establish reassessment intervals and prevention and mitigation plans	RM Program
Long Term Integrity Management Plans	Used to establish reassessment intervals and prevention and mitigation plans	RM Program
External Corrosion Direct Assessment Reports	Used to assess integrity of transmission pipelines and to establish reassessment intervals and prevention and mitigation plans on those lines	RM Program
In Line Inspection Reports	Used to assess integrity of transmission pipelines and to	RM Program

	establish reassessment intervals and prevention and mitigation plans on those lines	
Leak Root Cause Analysis	Used to study significant leaks across the transmission system in order to assess integrity of transmission pipelines and to establish reassessment intervals and prevention and mitigation plans.	RM Program
Risk Mitigation Plans	Used to identify threats and risk assessment results in order to establish reassessment intervals and prevention and mitigation plans	RM Program
Analysis and Studies of Specific Risks Associated with Particular Transmission Lines.	Used to assess integrity of transmission pipelines and to establish reassessment intervals and prevention and mitigation plans on those lines	RM Program

TAB 15

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6D
ACTIONS TO PROMOTE SAFETY ON LINE 132

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CHAPTER 6D
ACTIONS TO PROMOTE SAFETY ON LINE 132

A. Summary of Actions Taken to Promote Safety on Line 132

In OII Directive 3, the Commission directs PG&E to provide "a summary of actions PG&E took between 1955 and September 8, 2010 to promote safety with respect to its natural gas transmission pipelines in general and San Bruno's Line 132 in particular." OII, p. 18. In this chapter, PG&E responds to Directive 3 specifically with respect to Line 132.[1]

1. Summary of Line 132 Installation and Subsequent Construction

Line 132 is one of three local gas transmission lines that serve the San Francisco Peninsula. PG&E constructed Line 132 in two primary phases, in 1944 and 1948. The 1948 project installed approximately 18 miles of pipeline and included the section of Line 132 that runs through San Bruno.

a. 1948 Construction

In 1948, PG&E extended Line 132 north to expand gas transmission capacity in order to ensure that it could keep up with the rapidly increasing demand for gas service in and around the San Francisco Peninsula. The construction which installed the initial portion of Line 132 that traverses San Bruno began in August 1948.

The pipe PG&E used on the 1948 installation of Line 132 was designed to provide a high level of safety. PG&E ordered the pipe from Consolidated Western Steel Company, which filled the order from its Maywood facility in Southern California. PG&E's pipe order consisted of approximately 100,000 feet of 30" diameter electric fusion welded,[2] X52 Grade, 0.375" wall thickness (wt) steel pipe. Pipe Tally, Line 132 (1948) (P3-30001); Moody Engineering Invoice (1948) (P3-30002). PG&E

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1 PG&E responds to Directive 3 with respect to its entire transmission system in Chapters 6A, 6B and 6C.

2 This pipe is also referred to as submerged arc welded pipe, and in the case on the Line 132 pipe, Double Submerged Arc Welded (DSAW) pipe.

specifications called for 30' or 60' manufactured lengths of pipe. The specifications permitted up to 5% of the order to be comprised of "jointers" – two or more smaller sections of pipe joined together by welding -- though the individual lengths of pipe making up the jointer could be no shorter than 5 feet long. PG&E Pipe Specifications, Line 132 (1948) (P3-30003).

PG&E engaged Moody Engineering Company to inspect the manufacturing process and testing of the Line 132 pipe at Consolidated Western's plant; however, PG&E has not located the final report issued in connection with this inspection. Moody Engineering Invoice (1948) (P3-30002). PG&E has located a Moody Engineering Inspection Report for pipe ordered approximately 3 months later from Consolidated Western for Line 153, the specifications for which were identical in every respect to the Line 132 specification. Moody Engineering Pipe Inspection Report (1949) (P3-30004); PG&E Pipe Specifications, Line 131 (1949) (P3-30005); PG&E Pipe Specifications, Line 132 (1948) (P3-30003). The Moody Inspection Report for the Line 153 pipe explains Consolidated Western's manufacturing process and the quality assurance provided during the manufacturing process, as well as by Moody's inspection. Given that the two orders were nearly contemporaneous and that both orders were for the same pipe specification filled by the same manufacturer at the same mill with the same inspection company utilized, it is reasonable to conclude that the manufacturing and inspection processes were identical for both pipe purchases.

The pipe was made from plate steel of specific composition, rolled in 30' sections to approximately 29 ½ inches outside diameter and welded using the "Union Melt" process, also known as electric fusion welding or submerged arc welding. As the Moody Report explained, the Union Melt process used on the pipe made for PG&E involved double submerged arc welding (DSAW), whereby the long seam was welded first on the outside of the pipe and then on the inside of the pipe. The "Union Melt" DSAW process was a relatively new pipe manufacturing technology and represented a significant improvement over other longitudinal seam welding methods commonly used at the time for making large diameter pipe. Each 30' length of pipe was then hydraulically expanded (i.e., cold working) to its intended 30" outside diameter size, a process that also significantly strengthened the pipe. Each length of pipe was then hydrostatically tested to 1170 psig. While under pressure, a 2 pound hammer was repeatedly dropped on the long seam weld for 10 seconds to ensure the integrity of the weld. After manufacturing, Consolidated Western delivered the pipe to a third-party vendor, where it was double wrapped with hot asphalt coating to protect against external corrosion, and then trucked to the Line 132 job site.[3] Moody Engineering Pipe Inspection Report (1949) (P3-30004).

PG&E contracted the installation of Line 132 to an outside construction company. The contract provided specific standards to ensure quality construction and corresponding safety. Line 132 Construction Contract (1948) (P3-30006). For instance, PG&E required the contractor to follow specific welding and material standards described in the contract. Construction of this section of Line 132 was completed in November 1948.

b. The 1956 Relocation of Line 132 in San Bruno – Segment 180

In 1956, PG&E relocated a portion of Line 132 to accommodate a planned residential development in the Crestmoor neighborhood in San Bruno. The rerouted portion of Line 132 came to be identified as Segment 180. The project called for the use of approximately 1900 feet of the same type of 30" pipe that had been used in the 1948 construction of Line 132. 1956 Relocation, Line 132, Face Sheet (P3-30007). To enhance protection from external forces and potential third-party damage, the pipe was installed with approximately 48 inches of ground cover and relocated to where a street would be built with the planned development.

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3 Approximately 94,000 feet of pipe was used on the job. The remaining 6,000 feet was sent to contemporaneous projects or PG&E material storage facilities. Pipe Tally, Line 132 (1948) (P3-30001).

PG&E did not purchase pipe for the relocation project but completed the job using pipe held in its existing inventory. PG&E's records show that it had sufficient 30" Consolidated Western pipe on hand in 1956 to complete the relocation project with pipe previously ordered for but not used on Line 132 (1948), Line 153 (1949) and Line 131 (1953).[4] NTSB Data Response NTSB_036-015A (January 13, 2011), Docket No. SA-534, Ex. 2-AF (P3-30008).

The job file documents indicate that upon completion of construction Segment 180 was tested for leaks using the "soap test," which was a common method for identifying weld leaks during that era. Job Documents, Line 132, 1956 Relocation, pp. 167 & 168 (P3-30010). PG&E's Geographic Information System (GIS) and a 1968 filing with the Commission show that Segment 180 was also "gas tested" in 1961, which was another common method to confirm the integrity of pipelines during that era. CPUC Filing (1968) (P3-30011).

As noted in the NTSB reports publicly released to date, Segment 180 operated without incident for more than 50 years despite containing (unknown) short sections of pipe ("pups") that contained manufacturing defects in the long seam welds. NTSB Report, Metallurgy Group Chairman Report (January 21, 2011), Docket No. SA-534, Ex. 3-A (P3-30012).

c. Protecting Line 132 Against Potential Seismic Threat

In the mid-1980's, PG&E developed and implemented its Gas Pipeline Replacement Program (GPRP), the purpose of which was to prioritize and replace transmission and distribution facilities meeting certain criteria. See Chapter 6C for a discussion of PG&E's GPRP.

Following the 1989 Loma Prieta earthquake, identifying and protecting potentially vulnerable pipelines against seismic threats

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4 The 1948 and 1949 orders were filled at Consolidated Western's Maywood facility; the 1953 order was made at Consolidated Western's South San Francisco facility. Pipe Invoices, Line 131 (1953) (P3-30009); Moody Engineering Invoice (1948) (P3-30002); Moody Engineering Pipe Inspection Report (1949) (P3-30004).

became an increasing focus for both PG&E and the Commission.[5] Among other actions, as discussed in Chapter 6C, PG&E incorporated seismic threat into the evaluation and prioritization processes set forth in the GPRP, accelerating the upgrade in safety in seismically vulnerable areas. San Bruno Seismic Study, Lines 109 & 132 (1992) (P3-30014). In 1991, as part of this undertaking, PG&E conducted a detailed seismic and geosciences study to determine the potential threat to PG&E's three transmission lines in service on the Peninsula, Line 101, Line 109 and Line 132.

Thereafter, in 1992, PG&E conducted a separate and specifically focused evaluation of the potential seismic threat to Line 132 and Line 109 in the South San Francisco and San Bruno area (1992 Geo Hazards Study).[6] San Bruno Seismic Study, Lines 109 & 132 (1992) (P3-30014). Based on that study, PG&E initiated a GPRP project to relocate and/or replace several miles of Line 109 and specific sections of Line 132 that crossed or were otherwise vulnerable to stresses from the San Andreas and related earthquake faults.

As detailed in the 1992 Geo Hazards Study, Line 132 through the San Bruno area was generally not considered to be subject to significant seismic threat. However, Line 132 did cross the San Andreas fault in two locations south of Segment 180. San Bruno Seismic Study, Lines 109 & 132 (1992) (P3-30014). PG&E relocated the fault-crossing section of Line 132 (approximately 3,000 feet) to avoid the San Andreas fault. The same project replaced and relocated a short section of Line 132 in San Bruno (north of the Segment 180 rupture site) where the pipe was potentially subject to stresses of sufficient magnitude as to warrant this work. The existing 0.375" wt pipe was replaced with 0.500" wt pipe to increase protection against those stresses, and was relocated into the street to minimize the future threat of third-party damage. Job Face

5 Notably, PG&E's Peninsula transmission system suffered no breaks from the Loma Prieta earthquake, and its distribution system suffered only 3 breaks, all of which were in the Marina District. Map, Peninsula Transmission System & Marina District (P3-30013). Line 132, and Segment 180, withstood the earthquake without incident.

6 Line 109 and Line 132 run parallel through much of this region.

Sheet (1958719) (P3-30016). In accordance with then current regulations, the new pipe installed in both locations on Line 132 was hydrotested. San Bruno GPRP Hydro Test (1994) (P3-30015).

The 1992 Geo Hazards Study specifically evaluated whether other sections of Line 132 in the San Bruno area, including sections of Segment 180, should be replaced due to seismic threat, ground movement, or other threats presented by the vintage of pipe or method of construction. The study observed that Segment 180 was not subject to significant seismic or ground movement threat, and that the 1956 installation was a relatively newer pipeline constructed with welding technology and materials that were not considered to present seam or other concerns. San Bruno Seismic Study, Lines 109 & 132 (1992) (P3-30014).

d. Other Significant Replacement, Upgrade or Relocation Projects

Since Line 132 was installed in 1948, and Segment 180 in 1956, PG&E has undertaken many replacement and upgrade projects on Line 132 to ensure and enhance the integrity of the pipeline.

On numerous occasions, PG&E has enhanced safety on Line 132 by relocating and/or replacing sections of Line 132 when new development or other construction occurred. A brief list of such projects is presented here, which resulted in the installation of newer pipe, made and installed with better quality control than the pipe which was replaced:[7]

- relocated and replaced due to highway rebuild (GM 7002171 – 1997);
- relocated and replaced due to water district bridge construction (GM 4736906 – 1989);
- relocated and replaced due to Great America theme park construction project (GM 4522017 – 1986);

7 The “face pages” from the Line 132 construction projects since 1956, which include each of the projects called out in the text, are provided in the attached documents. Job Face Sheets (P3-30017 through P3-30074).

- relocated and replaced due to City of San Francisco sewer project (GM 1997626 – 1995);
- pipeline lowered and replaced due to reconstruction of drainage canal crossing right-of-way (GM 457741 – 1970);
- relocated, replaced, and installed casing due to railroad track construction (GM 426372 – 1965);
- relocated and replaced due to widening of Sand Hill Road (GM 145335 – 1959);
- relocated and replaced due to widening of Page Mill Road (GM 139437 – 1957); and
- relocated to accommodate Highway 280 construction (GM 159638 – 1964).

Several sections of Line 132 have been replaced or upgraded as part of PG&E's GPRP, which furthered the safety and integrity of Line 132. For example:

- replaced due to bell-bell chill ring girth welds and planned light rail development (GM 4952164 – 1994);
- replaced in preparation for planned paving project (GM 4746327 – 1989);
- replaced where future city development would prevent subsequent replacement (GM 4697454 – 1989); and
- replaced pipe that contained bell-bell chill ring construction prior to business park development in Milpitas (GM 4522165 – 1986).

PG&E also has replaced and/or upgraded parts of Line 132 to enhance safety in a variety of other ways. For instance, additional segments of Line 132 have been replaced or upgraded:

- to enable it to be inspected using in-line inspection technology (ILI), commonly referred to a "pigging" (GM 7064905 – upgraded Line 132 near San Jose to facilitate ILI because that section of pipeline was (uncommonly) subject to potential internal corrosion – 2007);
- to ensure appropriate cathodic protection and reduce external corrosion (GM 4007282 – installed insulated fittings, deep well anodes, and rectifiers to place a section of the pipeline under adequate cathodic protection – 1992) and (GM 7001206 - replaced

pipe where contact between casing and pipe created an obstacle to maintaining a satisfactory level of cathodic protection– 1996);

- where planned third-party activity would create risk to the pipeline (GM 433282 – replaced pipe where cover could be insufficient after planned future street grading – 1966); and
- to avoid potential future threats based on observed events (GM 183227 - relocated L132 and L109 in Woodside where expanded landslide activity could come close to the pipeline – 1974).

2. Line 132 Operations and Maintenance

The operation and maintenance of Line 132 were conducted subject to specific standards, policies and guidelines established by PG&E for its gas transmission system, and applicable regulatory requirements. PG&E reviewed and updated its operation and maintenance standards over the years, both as regulations and circumstances evolved, as is discussed in detail with respect to PG&E's entire gas transmission system in Chapter 6B.

a. Safe Pressures

The MAOP on Line 132 is 400 psig. That MAOP was established in accordance with the federal regulations enacted to promote and ensure pipeline safety. Specifically, 49 C.F.R. § 192.619(c) provides that the MAOP of an existing transmission line could be determined based on the highest operating pressure experienced on the pipeline between July 1, 1965 and July 1, 1970, and in consideration of the pipeline's condition, operating and maintenance history.[8] Documents memorializing historic pressures on Line 132 show that it operated at 400 psig in October 1968 (i.e., during the period specified in 49 C.F.R. § 192.619c). Line 132 MAOP Pressure Data (1968) (P3-30075). A substantial safety margin is built into transmission pipelines operating at MAOP levels.

b. Safe Practices

Since its installation in 1948 and continuing through today, PG&E has engaged in proactive replacement work, and operations and

[8] However, the MAOP cannot be higher than the hoop stress limit imposed by 49 C.F.R. § 192.611 (50% SMYS with regard to Line 132).

maintenance (O&M) actions. As detailed in Chapter 6B, PG&E's work procedures and standards provide specific guidance and requirements by which O&M activities are implemented, and require that appropriately qualified personnel are implementing them. The standards and procedures that broadly apply to PG&E's entire gas transmission system also have been generally applied to O&M activities on Line 132.

(1) Leak Identification and Repair

PG&E has performed leak surveys on Line 132, as it has on all of its gas transmission pipelines. As noted above, Segment 180 job file documents indicate that the relocated section of Line 132 was checked for leaks upon completion of construction in 1956. PG&E's GIS database and a 1968 CPUC filing show that Segment 180 was also gas tested in 1961.

Post-installation, PG&E has regularly conducted leak surveys on Line 132, including Segment 180, in accordance with both state and federal regulatory requirements. Historically PG&E has utilized both foot and vehicle leak survey methods on Line 132, and has kept pace with technological advancements in leak detection and operator training to effectively find the leaks.

PG&E's Line 132 leak surveys have identified, graded and monitored or repaired leaks. Most leaks have been identified on mechanical threaded connections such as on valves or other equipment located in PG&E station facilities, such as terminal yards and regulation pits.

During its leak surveys, PG&E has also located and repaired pipeline leaks. In 1988, during its regularly-scheduled foot leak survey, PG&E located a leak on Line 132 itself. Job Face Sheet (4701843) (P3-30063); A-Form, Line 132 (1988) (P3-30076). PG&E immediately excavated and replaced the section of pipe. The job file documents refer to the leak as a "longitudinal weld defect" but PG&E personnel who replaced the pipe have described the leak as a pinhole leak, i.e., a minor, non-hazardous leak likely resulting from porosity in the weld.[9] Nonetheless, consistent with its repair standard at the time, PG&E replaced 12 feet of the pipeline (as opposed to repairing the leak) to ensure that any potential concern with that pipe section was eliminated.[10] Job Face Sheet (4701843) (P3-30063); Pipe Repair Standard, A-65 (1988) (P3-30077).

(2) Avoiding Third-Party Damage

The single largest threat to Line 132 (and most all gas transmission lines in PG&E's system) is damage caused by third-party actions, such as construction crews or landowners engaged in excavation activities over the pipeline. As discussed in Chapter 6B, PG&E has developed over time programs to minimize the threat from third-party damage and ensure safety above and around its gas transmission lines.

As described in Chapter 6B, PG&E's mark and locate (M&L) procedures provide a fundamental safety tool to prevent third-party damage and the resulting consequences. In addition, PG&E undertakes (and has for many years) a comprehensive public awareness program to ensure the USA/811 One-Call System is common knowledge among the pertinent industries and to provide all targeted audiences with the information necessary to ensure pipeline safety. (PG&E's public awareness efforts are explained in detail in Chapter 6B.) In addition to written materials provided to PG&E's customers and non-customers, including to those within the potential impact area around Line 132, PG&E conducts outreach to various audiences at fairs and related trade shows. Recent seminars and outreach events PG&E has undertaken with respect to the Peninsula transmission system and the area around San Bruno are described along with other public awareness programs in

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9 As of the filing date, conflicting information suggests that the leak could have been located in the girth weld, rather than the long seam weld.

10 PG&E records show three girth weld-related leaks on Line 132 that were detected and appropriately repaired or closed. A-Form, Line 132 (2009) (P3-30147); A-Form, Line 132 (1979) (P3-30148); Leak Survey Form, Line 132 (1968) (P3-30149).

the attached documents. Public Awareness Materials (P3-30078 through P3-30146).

(3) Addressing External Corrosion

The second largest threat to Line 132 (and most of PG&E's gas transmission lines) is external corrosion. Beginning before the pipe was installed PG&E has taken actions to protect Line 132 against this time-dependant threat. In 1948, PG&E specified that the best-known protection against external corrosion (hot asphalt wrapping) would be applied to the DSAW pipe purchased from Consolidated Western. Moody Engineering Pipe Inspection Report (1949) (P3-30004). The pipe installed in 1956 on Segment 180 had the same quality outer protection. Pipe installed on Line 132 through the years also has been protected with the appropriate coating to minimize the external corrosion threat.

PG&E also has protected Line 132 against external corrosion with cathodic protection systems. As discussed in Chapter 6B, PG&E ensures that this cathodic protection effectively protects its pipelines, including Line 132, by regularly inspecting rectifiers and conducting pipe-to-soil tests to confirm that protection levels are satisfactory.

More broadly, PG&E maintains a policy of inspecting the pipe when it is exposed. When a section of Line 132 is exposed through excavation, regardless of the reason, PG&E strips off the coating and conducts a thorough inspection to verify both pipeline integrity and certain pipe specifications. An assessment is made of the degree of corrosion and the performance of the cathodic protection system, and the pipe surface is inspected for mechanical damage or other defects. H-Form, Template (2008) (P3-30150); A-Form, Template (2010) (P3-30151). Thus, by looking for potential issues unrelated to the reason the pipeline was exposed, PG&E continually strives to ensure that Line 132 remains safe, increasing the likelihood that latent potential threats will be discovered before becoming significant.

(4) Safe Operations

Line 132 has benefitted from applied advancements in operational technology. For instance, PG&E first equipped facilities on Line 132 with telemetry capability in the early 1970's.[11] PG&E continued to expand and improve those capabilities as technology advanced, culminating in the current supervisory communication and data acquisition (SCADA) technology. Telemetry, and SCADA in particular, has allowed gas system operators to monitor and analyze Line 132 conditions with real-time information and correspondingly operate the pipeline safely. Several valves on Line 132 also have remote control capability integrated with SCADA to provide gas system operators additional flexibility and control when directing or altering gas deliveries or shut-downs throughout the Peninsula system.

PG&E also has in place an emergency plan specific to the Peninsula division, which includes Line 132, in addition to PG&E's over-arching emergency plan applicable to its entire gas transmission system. Gas Emergency Plan, Peninsula Division, 2009 (P3-30152). As part of its public awareness program, discussed above, PG&E also conducts training for first responders, such as fire and police agencies. See also Chapter 6B. Prior to the San Bruno accident, PG&E undertook a variety of outreach actions and provided training opportunities for local first responders in the San Francisco Peninsula area, including live classes taught by qualified PG&E personnel. Public Awareness Materials (P3-30138 through P3-30145). Following the San Bruno accident, PG&E has stepped up these efforts with first responder agencies to both communicate important safety information and receive input regarding what additional actions PG&E can take to further facilitate integrated emergency responses.

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11 Telemetry technology permits automatic measurement and transmission of data from remote sources to central receiving stations for monitoring, analysis and recording.

(5) Inspecting and Maintaining A Safe Pipeline

PG&E works to promote safety on Line 132 through its inspection and maintenance procedures.

The 1988 replacement of 12 feet of pipe on Line 132 after a small leak was found during the regularly-scheduled leak survey is an example of PG&E promptly addressing conditions identified through its inspection process. Additional examples on Line 132 include:[12]

- 24-inch pipe replaced to eliminate potential risk from corrosion, leak history, and bell-bell chill ring girth welds (GM 7041177 – 2004);
- Replaced pipe damaged by third-party construction activities (GM 4657367 – 1988);
- Replaced pipe to facilitate replacement of leaking valve (GM 4622296 – 1987); and
- Damaged wrap planned for replacement; upon finding damaged bell-bell chill ring girth weld, entire pipe joint and weld were replaced (GM 47277 – 1995)

As is the goal, the need for immediate repairs on Line 132 has been minimized through the years by PG&E's regular inspection and maintenance on the line. The vast majority of safety-related upkeep on Line 132 occurs in the normal course of PG&E's inspection and maintenance. In addition to the regularly-scheduled leak surveys discussed above, PG&E inspects and services the valves, cathodic protection equipment, regulation and other facilities and appurtenances on Line 132 schedule.

Similarly, the PG&E personnel who perform the inspection and maintenance on Line 132, and who control the gas transported through Line 132 and the other Peninsula lines, receive extensive training and qualification testing. In the late 1990's, PG&E

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12 As noted, see attachments P3-30016 through P3-30074 for the job face sheets related to projects on Line 132.

centralized many of its training programs at the PG&E Academy.[13] With the adoption of Subpart N addressing qualification of pipeline personnel in 1999, PG&E established formal operator qualification training for a wide variety of covered tasks. *See* 49 C.F.R. § 192.801 et seq. PG&E's training and operator qualification programs are discussed in detail in Chapter 6B.

3. Integrity Assessments on Line 132

Both prior to and in accordance with state and federal integrity management regulations, PG&E has furthered safety on Line 132 through integrity assessments.

a. Integrity Assessment of Line 132 Prior to Subpart O

In the years prior to integrity management regulations and modern assessment methodologies, PG&E assessed Line 132 as part of its regular maintenance to confirm the integrity of the pipeline. For instance, PG&E used close interval survey to help determine where on the pipeline the greatest threat of external corrosion existed and, correspondingly, where to place protective equipment to minimize or eliminate the threat. As discussed in Chapter 6C, in the 1980's and 1990's until transitioning to the Subpart O structure, PG&E implemented integrity assessments and mitigation projects through the GPRP, pursuant to which sections of Line 132 were replaced and/or upgraded.

b. Integrity Assessment of Line 132 Pursuant to Subpart O

Formal integrity management regulation came into existence when Subpart O took effect in December 2003. Under Subpart O, operators had until December 17, 2004 to establish and follow an integrity management program consistent with the Subpart O requirements.

As early as 2003, PG&E assessed the integrity of sections of Line 132 using Direct Assessment (DA), before the integrity management regulations had taken effect. When PG&E undertook its first Baseline

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13 Among other innovations, as discussed in Chapter 6B, the PG&E Academy includes a real life training facility called "Sim City" (Simulation City), where, for example, trainees can use live equipment to search for, locate and grade actual gas leaks.

Integrity Assessment Plan (BIAP) in 2004, Line 132 was designated for priority assessment. Line 132 Baseline Assessment Plan, Rev. 5 (excerpts), (2009) (P3-30153). Consequently, Line 132 was among the first gas transmission lines assessed under PG&E's integrity management program. PG&E used External Corrosion Direct Assessment (ECDA) to assess Line 132 in 2004, in accordance with 49 C.F.R. §192.921. PG&E assessed Line 132 using ECDA again in 2009, two years ahead of the schedule mandated under the integrity management regulations. *See* P3-24141 to P3-24239. In accordance with Subpart O, PG&E also has developed a Long Term Integrity Management Plan (LTIMP) addressing integrity assessment and mitigation on Line 132. Long Term Integrity Management Plan, Nseg 132-2004 (P3-30154).

4. Conclusion

As described above, throughout the time period covered by OII Directive 3, PG&E has implemented procedures and taken actions to promote and maintain safety on Line 132.

TAB 16

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

PRE-SERVICE AND IN-SERVICE PIPE WELD DEFECTS AND FAILURES

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CHAPTER 7
PRE-SERVICE AND IN-SERVICE PIPE WELD DEFECTS AND FAILURES

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
PRE-SERVICE AND IN-SERVICE PIPE WELD DEFECTS AND FAILURES

A. Introduction

The Commission seeks to ascertain whether PG&E kept and maintained records of gas pipe weld failures or defects found before or after use between 1955 and September 2010 for approximately 5,800 miles of PG&E's DOT-defined natural gas transmission pipe. Additionally, the Commission directs PG&E to "identify the date and circumstances of the failures or defects, and provide all documents and data that pertain to such failures or defects." OII, p.19.

While PG&E maintains such records, what the OII directs is different from PG&E's ordinary use of these records. PG&E may use some of these records for integrity management or other pipeline engineering or maintenance purposes, but it does not generally need to use records dating back 55 years, and it never needs to work with all the records on all approximately 5,800 miles of pipeline at the same time. These records are generally accessed on an as-needed basis by personnel at various locations who perform engineering or maintenance work on the pipeline.

B. Responsive Records Produced by PG&E

1. Defining "Pipe Weld Defects and Failures".

Directive 7 of the OII asks for records of all "pipe" weld defects and failures. This language departs from other parts of the OII which seek records for "pipeline" (Directive 3). For purposes of responding to Directive 7 of the OII, PG&E initially conducted exhaustive searches of its records for weld defects and failures on gas transmission "pipe" as it is defined in federal regulations ("any pipe or tubing used in the transportation of gas, including pipe-type holders.") *See* 49 C.F.R. § 192.3 (definition of "pipe"). On June 8, 2011, after PG&E had gathered, collected, and reviewed more than 500,000 documents, and had isolated those records relating to pipe weld defects and failures on federally-defined "pipe," the definition of records responsive to Directive 7 was expanded to include "pipe, valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, deliver[y] stations, holders, and fabricated assemblies." Ruling Granting Motion for Extension of Time, pp. 4-5, June 8, 2011.

This expansion of the scope of responsive documents did not leave enough time for PG&E to conduct and complete a second review of its records to locate weld defects and failures on "pipeline," rather than only on "pipe." Accompanying this testimony, PG&E is providing records of weld defects and failures on "pipe," as well as those records of weld defects and failures on "pipeline" it could identify following the June 8 ruling. PG&E will provide additional records of weld defects and failures found on valves, compressor units, metering stations, regulator stations, delivery stations, holders, fabricated assemblies, and other appurtenances attached to the pipe on a rolling basis, but in no event later than September 30, 2011.

PG&E understands "weld" as used in the OII to mean both longitudinal seam welds and girth welds.

PG&E understands "defect" to mean the following: For pre-service weld defects, the term "defect" means any weld that did not meet standards of acceptability set forth in state and federal regulations. For in-service weld defects, the term "defect" means any pipe weld that results in repair or replacement of the pipe.

PG&E understands "failure" to mean the following: For pre-service weld failures, "failure" means any weld that leaked or ruptured during strength testing. For post-service weld failures, "failure" means any pipe weld that results in the release of gas.

PG&E refers to defects and failures discovered before a pipe is placed into service as "pre-service" in this document.

PG&E refers to defects and failures discovered after a pipe is placed into service" as in-service" in this document.

2. Pre-service Weld Defect and Failure Records are Almost Entirely Related to Girth Welds. All Defects and Failures are Repaired or Replaced Before the Pipe is Placed into Service.

The overwhelming majority of the records produced for pre-service weld defects and failures are found during x-ray inspections of girth welds conducted during an initial construction or repair project. Both girth weld and long seam weld defects and failures discovered during pre-service testing and inspection are repaired to meet regulatory standards or replaced altogether pursuant to PG&E standard practices and government regulations. Thus, records of pre-service defects and failures reflect successful pipeline quality assurance.

a. Circumstances of Weld Defects and Failures and Corresponding Records.

Over the last 55 years, PG&E has generally conducted two types of tests designed to identify weld defects before putting pipe into service.[1] First, PG&E has inspected girth welds using x-ray, visual, ultrasonic, and magnetic particle imaging as appropriate to determine whether welds meet regulatory standards.[2] Second, PG&E has performed pressure tests. Where these tests are performed, PG&E's practice has been to maintain records of pipeline weld inspections ("X-Ray documents") and Strength Test Pressure Reports ("STPRs") in Job Files associated with specific pipeline construction and repair projects. As part of PG&E's ongoing effort to validate the MAOP for its gas transmission pipelines, PG&E has collected thousands of Job Files associated with the 1,805 miles of HCA pipe. These files contain over 34,000 X-Ray documents and over 80,000 STPRs.

PG&E has reviewed each of these documents (as well as nearly 380,000 documents collected by the MAOP effort from Job Files but not yet categorized as any particular type of document) to identify

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[1] PG&E also has maintained, for certain of its pipe segments, mill test and inspection reports provided by pipe manufacturers that contain details and information relating to tests conducted at the mill. These reports may include information relating to defects and failures. An index of mill test and inspection reports indicating defects and/or failures is included as Attachment P7-0001. Responsive mill tests are included as Attachments P7-0002 through P7-0046.

[2] Regulatory requirements for pre-service weld inspections have changed over time. Prior to General Order 112 (1961), there were no regulatory requirements to inspect girth welds. General Order 112 called for natural gas utilities to inspect 30% of welds in Class 3 and 4 locations, and 20% of Class 1 and 2 location welds. General Order 112-C (1971) increased these percentages to 100% for Class 3 and 4 locations where practicable, but in no case less than 90%.

responsive X-Ray documents and STPRs that indicate the discovery of pipe weld defects and failures between 1955 and 2010. These documents relate to the construction of more than 1,800 miles of gas transmission pipeline.

X-Ray documents are most often created by contractors, and contain limited information regarding the circumstances other than the date, results, and PG&E Job File numbers associated with the inspection. PG&E is providing an index of X-Ray documents that indicate pre-service weld defects, and has extracted the date and Job File number associated with the inspection, where available. The index is included as Attachment P7-0047. X-Ray documents relating to the index are included as Attachments P7-0048 through P7-6935.

STPRs may contain information regarding the pre-service failure, such as the date, location, and Job File number associated with the construction job. PG&E is providing an index of STPRs that indicate pre-service weld failures, and has extracted the date and Job File number associated with the test. PG&E has also extracted the line and location of the test, where available. The index is included as Attachment P7-6936. STPRs relating to the index are included as Attachments P7-6937 through P7-6966.

b. Ancillary Pre-service Weld Defect and Failure Records.

Evidence of pre-service weld defects and failures may exist in other records. PG&E has located and reviewed a population of Construction Inspectors Notes files associated with specific pipeline projects. These files contain observations, forms, progress reports, drawings, and other documents (including X-Ray Documents and STPRs) provided by contractors and/or PG&E inspectors and construction supervisors that relate to the conditions and progression of pipeline construction projects. These Construction Inspectors Notes are not limited to HCA pipe. PG&E has reviewed each of these files, and has identified each file that contains evidence of pre-service pipe weld defects discovered during x-ray inspection of girth welds (no failures were discovered during hydrotesting in these files). An index of these defects is included as

Attachment P7-6967. Construction Inspector's Notes files relating to the index are included as Attachments P7-6968 through P7-7009.

3. In-service Weld Defects and Failures

a. Circumstances of Weld Defects and Failures and Corresponding Records.

The principal way PG&E identifies weld defects or failures that occur while a pipe is in service is when it detects and repairs a pipe leak. Over the last 55 years, PG&E has documented the discovery and repair of gas leaks on "A-Forms" (previously known as "Leak Test Reports" and "Pipe Shut Down" records). A-Forms have historically called for employees to capture information relating to the source and cause of the leak by entering specific codes on the document. The leak source codes available to employees included girth welds, longitudinal welds, and other welds. Prior to 2008, A-Forms included construction defects and material failures as options for the cause of the leak. In March 2008, PG&E modified the A-Form to enable field employees to record weld failure as the cause of the leak.

PG&E maintains A-Forms either in Job Files or in separate files located at approximately 70 of PG&E's local offices. PG&E has located and reviewed more than 4,500 A-Forms collected from HCA pipe Job Files through the MAOP validation effort. PG&E also maintains two relevant electronic databases that contain leak repair information. The first is PG&E's Integrated Gas Information System ("IGIS"), which includes electronic records of data obtained from A-Forms dating back to the early 1990s. PG&E can query this database for weld-related leaks. The second database is PG&E's Geographic Information System ("GIS"). GIS contains historic leak information derived from pipeline survey sheets. An index of in-service pipe weld defects and failures located in HCA pipe Job File A-Forms, IGIS, and GIS is included as Attachment P7-7010. Corresponding A-Forms and data from PG&E's electronic databases are included as Attachments P7-7011 through P7-7044.

PG&E also had a legacy electronic database that predated IGIS, and contains more detailed information on the source and cause of leaks than GIS. Called "PCLeaks," this legacy database was superseded by IGIS, and has not been in use since the mid-1990s. PG&E is evaluating the leak data in PCLeaks, and will supplement its production if additional responsive information is found.

PG&E is currently undertaking to collect A-Forms from each of its local offices, and plans to complete collection and review of these documents by September 30, 2011. PG&E will supplement its production with any additional responsive A-Forms.

b. Ancillary In-service Pipe Weld Defect and Failure Records.

As with pre-service records, PG&E maintains other records that, while not serving as a primary source of in-service weld defect and failure data, may contain inspection reports that indicate in-service weld defects and failures. These documents include Transmission Integrity Management pipeline assessments, pipe analysis reports conducted by PG&E's Applied Technology Services group, and Material Problem Reports submitted by field employees upon discovery of a pipe weld defect or failure.

1. Integrity Management Assessments.

PG&E conducts Integrity Management assessments of its gas transmission lines to assess risks to the pipelines, including pipe weld defects and failures. These inspections (both in-line inspection and direct assessment) may reveal the presence of pipe weld defects and failures. These assessments have been conducted since 2004[3] in compliance with federal regulations implemented at that time. An index of pipe weld defects and failures discovered during Integrity Management assessments is included as Attachment P7-7045. Documents and data

[3] PG&E conducted some inline inspections prior to enactment of the federal integrity management regulations. Several of the records produced are from one such inspection conducted in 2002. *See* Attachment No. P7-7046.

corresponding to entries on this index are included as Attachments P7-7046 through P7-7049.

2. Failure Analysis Reports from PG&E's Applied Technology Services Group.

PG&E operates an engineering support services group currently known as Applied Technology Services ("ATS"). This organization has existed since long before 1955, and has performed failure analysis for PG&E's gas and electric operations. ATS's services include testing following the discovery by a field employee of a pipe defect or failure. This testing helps to identify the root cause of gas incidents and mitigate the likelihood that such events may occur in the future. An index of pipe weld defects and failures discovered during ATS testing is included as Attachment P7-7050. Documents and data corresponding to entries on this index are included as Attachments P7-7051 through P7-7089.

3. Material Problem Reports.

PG&E's Supplier Quality organization maintains records of Material Problem Reports that may be submitted by field employees upon discovery of equipment or materials that are faulty, that do not meet specifications, or that fail in service. While not intended to be specific records of weld failures or defects, these reports may contain evidence of weld failures and defects. PG&E presently maintains hard copies of Material Problem Reports from 1989-1994, and maintains an electronic database of reports submitted between 1995 and the present day. An index of pipe weld defects and failures indicated on Material Problem Reports is included as Attachment P7-7090. Documents and data corresponding to entries on this index are included as Attachments P7-7091 and P7-7092.

4. Additional Records

PG&E has located additional materials which, while not primary records of pipeline weld defects and failures, are responsive to the Commission's request. Many of these documents are produced in Chapter 6C. An index of additional documents containing evidence of pipe weld defects and failures is included as Attachment P7-7093. Documents and data corresponding to entries on this index are included as Attachment P7-7094.

5. Subsequent Productions

PG&E will produce additional records of pipe weld defects and failures on a rolling basis through September 30, 2011, including defects and failures on “pipeline” that are not produced with this testimony. PG&E will provide supplemental indices containing similar details of pipe weld defects and failures, as well as the documents and data corresponding to the defects and failures.

TAB 17

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

IDENTIFICATION OF WITNESSES

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CHAPTER 8
IDENTIFICATION OF WITNESSES

A. Introduction

As requested in Directive 8 of the OII, the table below provides the names and titles of the individuals who will sponsor the various chapters and sections of this response.

Ch.	Subject	Witness
1	Regulatory History	Cesar De Leon, Pipeline Safety Engineering Consultant (Sections C & E)
1A	History of PG&E's Gas Transmission System	Kirk Johnson, VP - Gas Engineering and Operations
2	Current Document Retention Policies	Brian Daubin, Director - Continuous Improvement Initiatives
2A	Record Keeping Policies and Practices (1955-2010)	Brian Daubin, Director - Continuous Improvement Initiatives
2B	Record Keeping Challenges in the Gas Transmission Industry	Ed Ondak, Pipeline Safety Expert, Consultant
3	Discussion of Specified NTSB Reports	Bob Fassett, Director - Integrity Management and Technical Support
3A	Supplemental Discussion of Specified NTSB Reports	Bob Fassett, Director - Integrity Management and Technical Support
4	Relationship of GIS Records Discrepancy To San Bruno Rupture	Bob Fassett, Director - Integrity Management and Technical Support
5	Discussion of How Seamless Error Occurred	Brian Daubin, Director - Continuous Improvement Initiatives
6	Actions to Promote Safety on PG&E's Gas Transmission System	Kirk Johnson, VP - Gas Engineering and Operations
6A	Actions to Promote Safety – Design, Construction and Testing	Gary Grelli, Manager - Pipeline Engineering

6B	Actions to Promote Safety – Operations and Maintenance	Brad Spainhower, Superintendent – Maintenance & Construction Gas Transmission
6C	Actions Promoting Safety -- Safety Risk Assessments	Bob Fassett, Director - Integrity Management and Technical Support
6D	Actions to Promote Safety – Line 132	Jim Grinstead, Consultant, Retired PG&E Engineer
7	Weld Failures/Defects	Bob Fassett, Director - Integrity Management and Technical Support