Docket No. SA-534

Exhibit No. 2-A

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

OPERATIONS GROUP CHAIRMAN'S FACTUAL REPORT

(27 Pages)

National Transportation Safety Board

Washington, D.C. 20594

OPERATIONS CHAIRMAN FACTUAL REPORT

A. Accident

Accident Number: DCA10MP008
Type of System: Natural Gas Transmission Pipeline
Accident Type: Pipeline Rupture
Location: San Bruno, California
Date: September 9, 2010
Time: approximately 6:11 pm
Owner/Operator: Pacific Gas and Electric Company
Material Released: Natural Gas
Pipeline Pressure: 386 - 396 psi at time of rupture
Component Affected: 30 inch diameter pipeline

B. Group Chairs

Karl Gunther NTSB — Operations Group Chair
Matthew Nicholson NTSB — SCADA Group Chair

Members:

Sunil Shori
Utilities Engineer
Consumer Protection & Safety Div
Utilities Safety & Reliability Branch
State of California Public
Utilities Commission
505 Van Ness Avenue, 2nd floor
San Francisco, CA 94102-3298
[redacted]

Robert Fassett
Director – Integrity Management
And Technical Services
Pacific Gas and Electric Company
375 N Widget Lane
Walnut Creek, California 94598
[redacted]

Mark Kazimirsky
Supervising Engineer
Pacific Gas and Electric Company
375 N Wiget Lane
Walnut Creek, CA 94598
[redacted]

Peter J. Katchmar
Accident Coordinator
PHMSA
12300 West Dakota Avenue
Suite A-110
Lakewood, CO 80288
[redacted]

Andy Wenzel
Supervisor, Gas System Operations
Pacific Gas and Electric Company
77 Beale Street, Room 1641
San Francisco, CA 94105
[redacted]

Klara A. Fabry, P.E.
City of San Bruno
Public Services Director
567 El Camino Real
San Bruno, CA 94066-4247
[redacted]

C. <u>Accident Summary</u>

SYNOPSIS

On September 9, 2010, at approximately 6:11 p.m. Pacific Daylight Time, a 30-inch diameter section of a multi-diameter intra-state natural gas transmission pipeline (Line 132) owned and operated by Pacific Gas & Electric Company (PG&E) ruptured in a residential area in San Bruno, California. The rupture occurred at approximately mile point (MP) 39.28, at the intersection of Earl Avenue and Glenview Drive in the city of San Bruno. PG&E estimated that 47.6 million standard cubic feet (MMSCF) of natural gas were released as a result of the rupture. The rupture created a crater approximately 72 feet long by 26 feet wide. A pipe segment approximately 28 feet long was found about 100 feet south of the crater. The released natural gas was ignited sometime after the rupture; the resulting fire destroyed 38 homes and damaged 63. Eight people were killed, numerous individuals were injured, and many more were evacuated from the area. On September 10, the NTSB launched a team to California to investigate this tragedy.

Line 132 is regulated by the California Public Utilities Commission (CPUC). According to the PG&E survey sheets, the ruptured pipe (part of Segment 180 that is approximately 1,742-feet long) was constructed from 30-inch diameter seamless steel pipe (API 5LX) Grade X42 with 0.375-inch thick wall. The pipeline was coated with hot applied asphalt, and was cathodically protected. The ruptured pipeline segment was installed circa 1956. The specified maximum operating pressure (MOP[1]) for the ruptured pipeline was 375 pounds per square inch gauge (psig). According to PG&E, the maximum allowable operating pressure (MAOP[2]) for the line was 400 psig. Just before the accident, PG&E was working on their uninterruptable power supply (UPS)[3] system at Milpitas Terminal (Milpitas), which is located about 39.28 miles southeast of the accident site.

Figure 1: Accident Location – PG&E Line 132 Rupture, San Bruno California

[1] Maximum Operating Pressure is an operating limit defined by PG&E.
[2] Maximum Allowable Operating pressure is defined under 49CFR192 as the maximum pressure that a pipeline or pipeline segment may be operated.
[3] This was the UPS system for the Milpitas station. An uninterruptable power supply is an electrical apparatus that, in the event of loss of incoming normal power, provides backup power (battery bank) to equipment or devices for a limited duration until normal power can be restored or an emergency power source can be brought online.

D. Pre- Accident Actions of September 9th 2010

A work request or clearance submitted on August 19th of 2010, MIL 10-09, and approved by Gas Control for the replacement of an UPS at the Milpitas Terminal was being executed on the afternoon of September 9th 2010. The work was in support of a project that would replace the station UPS which had failed (switched to internal bypass) in March of 2010. The electricians were working to remove the load on the UPS electrical distribution panel[4] for replacement along with the UPS. In order to replace the UPS panel, but maintain redundancy for critical components, the electricians were transferring load from each circuit onto individual mini[5] UPS devices. The mini UPS would maintain power to critical station instrumentation until the generators could start in the event of a loss of normal power to the station. During this work, while transferring loads from the last circuit in the UPS electrical panel, two (redundant) 24vdc power supplies (PS-A and PS-B)[6] serving station instrumentation failed or experienced a loss of ac power. The Supervising Engineer of the SCADA controls group told NTSB investigators during an interview that a bench test conducted by PG&E after Sept 9th 2010 revealed dc voltage output from each of the power supplies was below the rated 24 volts.

The loss of dc power to the pressure transmitters and position sensors at the regulating valves[7] and monitor valves[8] resulted in zero or out of range readings to the Siemens controllers[9] and Programmable Logic Controller (PLC)[10]. Multiple Siemens controllers would also fail to come back online properly during this work; requiring reprogramming. During the loss of power, the line pressures and valve positions were all indicating a zero value. The regulating valve controllers responded to a zero pressure (below set point) by commanding the valves open until they reached 100% while the position sensors continued to indicate a closed valve status over SCADA. Once the regulating valves were wide open, pressure was no longer controlled through the primary path and the pneumatically operated monitor valves became the sole means of pressure control

---

4 An electrical panel with circuit breakers for distributing power to multiple loads.

5 Small scale Uninterruptible Power supply directly serving a single component on a circuit as opposed to a large scale UPS that would backup multiple loads.

6 Power supplies A & B were installed with diodes as redundant power supplies supporting transmitters.

7 The regulating valves operate in parallel pairs (trim and load) as the primary means of pressure control through the Milpitas station. These are full port valves with electric actuators controlled by Siemens controllers. They can either modulate to a percent open to maintain a downstream pressure or be given a percent open by the gas system operator.

8 The monitor valve or monitoring valve is a full port, normally open, pneumatically controlled and actuated valve that is preset at a pressure above the maximum operating pressure on the line. In the event of a regulator or control valve failure the monitor valve will begin to modulate and regulate line pressure once the line pressure begins to exceed the set point value on the valve.

9 The Siemens controllers (controllers) are stand alone loop controllers that are installed on each regulating valve at the Milpitas station. The controllers communicate with the PLC and modulate the control valves based on downstream pressure readings or percent open.

10 Programmable Logic Controller is a microprocessor-based system which provides system automation by monitoring sensors and controlling actuators in near real time.

at Milpitas. The monitor valves began to throttle from wide open to control discharge pressure when the sensing line detected a line pressure that exceeded the set point. The regulating valves modulated to maintain a line pressure of 375 psig or less based on the set point selected by the gas system operator. The monitor valve controllers at Milpitas had a set point value of 386 psig[11]. The gas control technician at the Milpitas station only became aware of the loss of control to the regulating valves when a gas system operator called the station to alert them of high and high-high alarms downstream.

Timeline of Events at Milpitas:

The first call to the SCADA[12] control center in San Francisco is recorded at 2:46 pm on September 9th 2010, from the Milpitas station gas control technician to gas system operator "A" explaining that work was taking place on clearance number MIL-10-09. The gas control technician mentioned that the Siemens 353 controllers[13] were already switched to mini UPS power and that the Chromatograph and PLC were going to be transferred next resulting in a loss of communication for up to 10 minutes.

At 3:36 pm a second call was received at gas control from the Milpitas gas control technician, this time gas system operator "B" answered the phone. The two discussed the transfer of the PLC to the mini UPS. The station technician questioned the operation of regulating valves 1 and 2 on lines 300A and 300B and whether they are fail-close valves. The gas control technician decided to lock the control valves in an open position at the station. The gas system operator notified the technician that they were flowing approximately 10 MMSCFH (million cubic feet per hour) through line 300B.

At 4:03 pm the Milpitas gas control technician called the control center again and informed gas system operator "C" that power would be disrupted for the PLC Genius blocks[14]and the flow computer[15]. The gas control technician explained that the control valves would be placed in manual control[16] during the work and that he would record the set points so that when the control valves are returned to automatic control the gas system operator would be able to determine whether the station was operating the same as before the work.

[11] The Monitor valve set point is set locally at the valve by moving an indicator on the front of the panel. PG&E's monitor valves are set above the MOP of the line but below the MAOP. SCADA Operators have the ability to remotely set the monitor valve position but cannot override the local set point pressure.
[12] SCADA is Supervisory Control and Data Acquisition and is comprised of a network of PLCs/RTUs, field sensors and communications that allow gas transmission system monitoring, data archiving and remote operation of equipment (valves, compressors, etc…).
[13]The Siemens controller controls the operation of the regulating valve using a pressure input signal from the pressure transmitter to control the valve position
[14] I/O Module that communicates with the PLC and includes discrete and analog inputs and outputs
[15] Flow computers calculate, analyze and process data from pipeline and distribution operations
[16] Placing the regulating valves in manual was performed at the Siemens's controller and not at the valve actuator.

From 4:18 pm to 4:24 pm the alarm logs[17] showed all of the regulating valve controllers at Milpitas displaying the alarm status 'Aut/Man' and 'Con/Loc,' indicating that work had begun at the station. These alarm texts appear in the log as red, signifying high severity. From 4:24 pm to 4:32 pm several pages of low-low pressure alarms appeared at the gas system operator console[18] followed by 'Monitor valve not open' alarms and then more control valve alarms indicating that the normally open monitor valves were shut at Milpitas.

Shortly after 4:32 pm and until 4:38 pm the alarm logs showed that the Milpitas alarms began to clear[19] on their own as many others were being acknowledged by a gas control operator and one other person. The transfer on these devices was complete and the system was returning to normal operation. At 4:38 pm the Milpitas gas control technician notified gas system operator "D" to expect communication errors or interruptions to the SCADA data as they move into the next phase of transferring load from the electrical panel. By 4:46 pm the Milpitas gas control technician notified gas system operator "D" that the gas control technician and electrician were ready to transfer over to the mini-UPS power supply and that they could expect communication errors for the next 5 minutes.

From 5:01 pm to 5:12 pm the alarm logs indicated regulating valve controller errors at Milpitas. The controller alarms were followed by monitor valve "not open" alarms at 5:21 pm and then by pressure out of range alarms and more controller error alarms through 5:22 pm. From 5:22 pm to 5:23 pm the alarm logs began to show high differential pressure and backflow alarms at Milpitas which became high pressure alarms on Lines 100, 101 and 109 by 5:25 pm. The high and high-high pressure alarms indicated the pipelines were operating above their rated MOP.

At 5:28 pm the gas system operator "C" called the Milpitas gas control technician to report the high pressure alarms coming in to his console from downstream of the Milpitas station at Silver Creek, Tully Road, Aborn and White, Irvington and North Rengstorff. The gas control technician at Milpitas realized, while on the phone, that the regulating valves had opened at the station. Meanwhile, the gas system operator's console reported zero pressures at the Milpitas terminal with all valves showing a closed state.

At 5:30 pm, the gas system operator "D" notified the gas control technician over the phone stating that his console was showing 458 psig at the mixer and did not display any pressures downstream of the mixer. The gas

[17] Alarm logs are archived entries of the Alarm screen from the gas system operator's console.
[18] The console is the gas system operator's desk and screens that display the SCADA information (alarms, pressures, flows) relating to the operation of the pipeline.
[19] An alarm may clear or be acknowledged. A cleared alarm indicates that the condition that caused the alarm has been corrected. An acknowledged alarm is one that the gas system operator has been alerted to and recognized but has not necessarily been cleared.

system operator suggested that the station bypass valves (valves 29 and 62) had opened during a loss of power to the pressure transmitters. He further believed that the primary regulating control valves had gone fully open, leaving only the monitor valves to maintain pressure control out of Milpitas. The gas system operator and gas control technician attempted to determine how to get the station configured to the way it was before the work had started. During the discussion, the gas control technician mentioned that they had transferred everything to mini-UPS power and had de-energized the electrical panel but there must have been a load that was unaccounted for on the last breaker causing it to lose power.

At 5:36 pm the Milpitas gas control technician called gas system operator "D" and confirmed that the Mixer bypass valve (valve 29) had been closed. All of the regulating valves appeared closed over SCADA so the gas system operator requested that the gas control technician visually check each of the regulating valves to confirm the valve positions.

At 5:42 pm the Milpitas gas control technician called gas control and spoke with gas system operator "C". He reported that the control valves 7 and 7R (controlling valve set on line 300B) had opened fully. The gas system operator "C" discussed[20] this with gas system operator "D" who stated that these valves should be controlling the downstream pressure. Gas system operator "C" explained to the Milpitas gas control technician that he was unable to see valid pressures or valve positions on the SCADA console. The Milpitas gas control technician asked if he could reduce the local set point of the pneumatic controller at the monitor valves from 386 psig to 370 psig to try and bring the line pressures out of high-high alarm[21]. The gas system operator "C" agreed to this after a brief discussion with operator "D".

At 5:48 pm the gas control center gas system operator "C" received a call from the alternate gas control center (Brentwood) where a gas system operator questioned the high-high flow alarms at Irvington, downstream of Milpitas. The alarms appeared at 5:20 pm and gas system operator "C" confirmed with gas system operator "D" that this was a result of the loss of control at Milpitas.

At 5:55 pm gas system operator "D" spoke to the Milpitas gas control technician who reported that the station bypass valve 62 was closed and in manual control and that monitor valve 5 (upstream of the 8 & 8R regulating valves serving incoming line 300B) was also closed. The gas system operator stated that the monitor valve should stay closed since SCADA was showing almost 500 psig downstream. The gas system operator asked the station technician to place a

[20] The gas system operators sit next to one another in the San Francisco control center and are able to communicate from their console.
[21] High-high alarm is set at 375 psig or MOP for line 132. This is discussion is captured in the control room transcripts. Without the regulating valves working correctly (loss of transmitter power), the monitors are the only means of pressure control.

pressure gauge downstream of the mixer at station valves 48 or 49 to get a reading of the station discharge pressure.

At 6:04 pm the gas system operator "D" informed the gas control technician supervisor that the control center had reduced the discharge set points at the PLS-7 and Sheridan Road Station (incoming transmission lines) to 370 psig to lower the incoming pressure at Milpitas. At the same time, the gas control technician at Milpitas reported to gas system operator "C" that he obtained a pressure reading of 396 psig from the gauge installed downstream of valve 49 and the regulator on Line 132. High-high pressure alarms continued to show up in the alarm logs from this time through approximately 6:15 pm.

By 6:15 pm the Martin Station[22], downstream of Milpitas, displayed the first low pressure alarm on the alarm screen. At 6:18 pm a PG&E off duty employee reported a large explosion and fire in San Bruno to the Concord Dispatch center. The dispatcher indicated that he would notify a supervisor.

At 6:27 pm the Concord dispatch center called the gas control center and spoke to gas system operator "C" and inquired if they observed any pressure drop near the San Bruno area. The dispatcher indicated that he received reports of a flame shooting up in the air with and the sound of a jet engine. The dispatcher said that he had dispatched a PG&E supervisor and a gas service representative to the area. The gas system operator replied to the dispatcher that gas control had not received any calls about the incident.

At 6:29 pm gas system operator "D" called alternate Gas Control (Brentwood) to let them know about the potential line break on Line 132[23]. The gas system operator "D" conveyed that they have a line break in San Bruno with flames and Martin pressures are "dropping like a rock." He stated that Line 132 pressure was up at 396 psig and now it's down to 56 psig. Operator "D" further stated that there had been an over pressure event at Milpitas earlier.

[Exhibit 2-G: Milpitas Terminal one-line diagram]
[Exhibit 2-I: SCADA Alarms 9-9-2010 from18:04 thru 18:39]
[Exhibit 2-K: SCADA Pressure Readings 9-9-2010 from 16:12 through18:42]
[Exhibit 2-L: Photograph of Monitor Valve Pneumatic Controllers]
[Exhibit 2-M: PG&E Pressure Transducer Locations for Line 101, 109 and 132]
[Exhibit 2-N: PG&E SCADA Trends from 9-9-2010]
[Exhibit 2-Y: Control Room Transcripts]

[22] Martin station is the next terminal approximately 46 miles downstream of the Milpitas terminal.
[23] The persons holding this discussion have not yet been identified from the control room transcripts.

E. PG&E Emergency Response

The rupture occurred at approximately 6:11 pm. Simultaneously, a high-high pressure of 386 psig was recorded at the Martin station located 19 miles downstream of the rupture site. By 6:16 pm Martin station was in low-low alarm status having dropped in pressure to 144 psig. The PG&E dispatch center located in Concord, California (northeast of Oakland) was first notified of an explosion in the San Bruno area at 6:18 pm by an off duty PG&E employee. By 6:30 pm the PG&E gas control center connected the pressure drop alarms at Martin with the overpressure at Milpitas and the news reports at San Bruno and realized there had been a rupture of the system. Gas Control then tried to determine where the rupture was located and isolate that section.

At 6:23 pm, the Concord dispatch center dispatched a PG&E gas service representative from Daly City to respond to the scene of the pipeline rupture. An off-duty on-call supervisor who lived about 4 miles from the rupture site learned of the incident through media reports and notified dispatch that he was also responding to the scene. The gas service representative and the on-call supervisor were the first PG&E employees to arrive on-scene at approximately 6:41 pm.; however neither of these individuals was qualified to operate mainline valves. The gas service representative responded to the scene when he was dispatched and followed instructions from management. The on-call supervisor checked in with the San Bruno Fire Department battalion chief and confirmed he was the first PG&E representative on the scene. He contacted the PG&E gas control center in San Francisco and reported the fire was caused by a rupture of PG&E's transmission pipeline. He then contacted the gas Maintenance & Construction Superintendent who in turn activated PG&E's Peninsula Office Emergency Center (OEC). The on-call supervisor then became the PG&E incident commander and interfaced with the overall incident commander, the San Bruno Fire Department battalion chief.

At 6:35 pm, an off-duty mechanic qualified to operate mainline valves notified Concord dispatch about the fire and proceeded to the PG&E Colma yard to obtain the tools to shut off mainline valves. At about 6:40 pm the on-call supervisor requested that a second mechanic also respond to the PG&E Colma yard to assist the first mechanic. At about 6:45 p.m., the Concord dispatch center directed other PG&E crews to isolate the gas transmission line; however, the response time for these crews was about two hours due to the distance from the rupture site from where they were dispatched and the heavy traffic on the highway.

The two mechanics left the PG&E Colma yard at 7:06 pm and arrived at the first mainline valve at 7:20 pm. At 7:29, Gas Control closed valves V-10 and V-13 at Martin Station. The mainline valve upstream of the rupture location (valve at MP 38.49) was closed at 7:30 pm which isolated the Line 132 rupture. Additionally, the two valves downstream of the rupture (MP valves 40.05 and

40.05-2) were closed at 7:45 pm at Healy Station to narrow the isolated section and allow for backfeed into Line 132 downstream of the rupture site.

[Exhibit 2-B: PG&E Event timeline]
[Exhibit 2-C: 49CFR §192.619(a)(3) and PG&E documentation]
[Exhibit 2-BV: Gas Controller Interview]
[Exhibit 2-DF: Gas Distribution and Construction Superintendent Interview]

F. Accident Scene

The crater generated from the pipeline rupture was measured at 72 feet long and 26 feet wide. A 27 foot 8 inch pipe section was found approximately 100 feet 7 inches south of the crater location. The tops of the two pipes remaining in the excavation were at the same elevation but offset horizontally from each other by 1.5 degrees. Nearby utilities included a 6 inch cast iron water main, a 10-inch sanitary sewer line and 4-inch gas distribution line. The sewer line is visible under the south end of separated pipe section and the 4 inch gas distribution line is visible running parallel to the transmission line (figure 2).

The pipeline had a north alignment at this location and the flow of gas was to the north under typical conditions. The southern section of pipe measured 12 foot – 4 inch at its longest point and was comprised of a single piece of long pipe. The center section was 27 foot – 8 inch at its longest point and was comprised of the same long joint continuing from the southern section as well as four shorter lengths of pipe (pups). The northern section of pipe measured 15 feet – 9 inches and was comprised of two pups and a long joint. For convenience the pups were numbered 1 through 6 in the south to north direction. The circumferential welds (i.e. girth welds) that joined the pups were numbered sequentially from south to north as C1, C2, and so on through C7.

The center section had circumferential fractures at both ends. One fracture was through the long joint to the south of pup 1. The other fracture was at the girth weld between pup 4 and pup 5. There was a longitudinal fracture in pup 1 that continued in the long joint south of pup 1 to the circumferential fracture at the south end of the center section. There were circumferential fractures in girth weld C2 between pup 1 and pup 2 on both sides of the pup 1. In the counterclockwise direction, the circumferential fracture measured 27 inches (note: Clockwise and counterclockwise directions are assigned as a rotation about the longitudinal axis of the pipeline looking north). At the end of the fracture there was a 10 inch diameter circular depression in the pipe. In the clockwise direction, the circumferential fracture measured 6.25 inches, at which point it intersected with a longitudinal fracture in pup 2. The longitudinal fracture in pup 2 extended 29.25 inches from girth weld C2 at which point it branched in two. One branch continued in the longitudinal direction to within 3 inch of girth weld C3. The other branch was angled 66° to the longitudinal direction and measured 18 inches. The circumferential fracture at the north end of the center section deviated from girth weld C5 along a 3.5 inch circumferential length up to 1 inch longitudinally in pup 4.

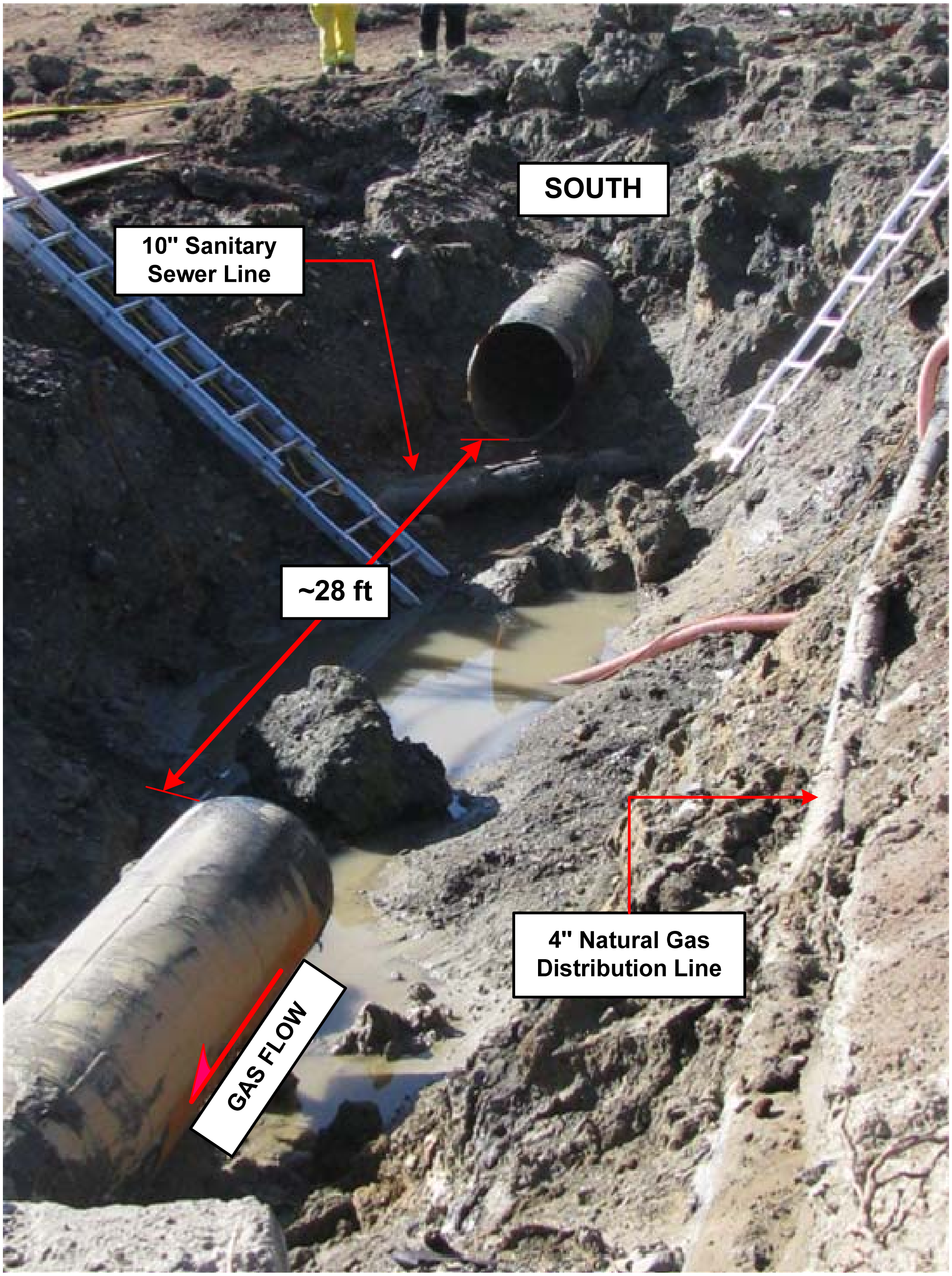

Figure 2: Photo of accident crater upon arrival by the NTSB Investigators

The ruptured pipe section and segments cut from the north and south side of the rupture segments were shipped to the NTSB Training Center in Ashburn, Virginia, for examination and arrived approximately 11:00 am September 16, 2010.

[Exhibit 2-D: Schematic showing relative locations of nearby services and L132 in the trench]

G. Pipeline Operator Information

Pacific Gas and Electric Company was incorporated in California in 1905 and is based in Walnut Creek, California. The company is a subsidiary of the PG&E Corporation. The company provides natural gas and electric service to approximately 15 million people throughout a 70,000 square mile service area in northern and central California. This area stretches from Eureka in the north to Bakersfield to the south and from the Pacific Ocean to the west to Sierra Nevada Mountains to the east. The gas facilities include 42,141miles of natural gas distribution pipelines and 6,438 miles of transmission pipelines. PG&E and other intrastate public utilities in the state are regulated by the California Public Utilities Commission (CA-PUC).

H. Pipeline Information

Line 132 is comprised of 24-inch, 30-inch, 34 inch and 36 inch diameter segments that make up one of the three transmission lines of PG&E's peninsula system. The gas flows through all three lines from south to north. Line 132 delivers gas from the Milpitas terminal to Martin Regulation Station approximately 46 miles north.

The pipeline survey sheet for Line 132 described this section of Line 132 (also described on the sheet as section 180) at Glenview Drive and Earl Avenue was 30 inch seamless pipe installed in 1956. PG&E obtained this information from accounting records and not engineering drawings. PG&E records show that the line MAOP was established under 49CFR §192.619(a)(3). The peninsula system is comprised of lines 101, 109 and 132 and includes six crossties between the three lines spaced along the full length to allow gas to flow between transmission lines.

In 1956 a PG&E project relocated approximately 1,851 feet of Line 132 that had been originally constructed in 1948. This relocation started north of Claremont drive and extended south to San Bruno Avenue rerouting Line 132 from the east side to the west side of Glenview Drive. At the intersection of Earl Avenue and Glenview drive there was a local low spot in the pipeline where the pipe had to traverse two hills. In 1961 a PG&E project was completed on L132 immediately to the south of the 1956 relocation. As a result only 1,742 feet of the original 1,850 feet of pipe from the 1956 project remained in operation.

The pipeline coating chosen was hot applied asphalt enamel and the pipe included cathodic protection using a dc rectifier system. The pipe was documented in the PG&E Geographical Information System (GIS) database as "Nom Dia. of '30' smls Grade X-42 pipe". This database was populated from a Pipeline Survey Sheet using a line item description from a 1956 Journal Voucher used to allocate material expenses from one construction job to other construction jobs.

On June 6, 2008 the City of San Bruno had a contractor (D'arcy and Harty construction) install approximately 300 ft of new sanitary sewer main along Earl Avenue to Glenview Drive using a pipe bursting method. They were replacing a 6 inch terra cotta pipe with a 10 inch polyethylene pipe. The contractor notified USA[24], that is a one-call service for the area and filed the required notices. PG&E had a gas mechanic on the site Friday June 6, 2008 when the hand digging begun and Monday June 9, 2008 when the gas pipeline crossing was completed. The PG&E inspector measured the distance from the new sewer pipeline and inspected the gas pipeline for damage and was satisfied with the work and did not mention any problems to the contractor foreman.

[Exhibit 2-P: PG&E Alignment Sheet Line 132]
[Exhibit 2-AP: GM 151181 and 1961 L-132 Relocation Project Documentation]
[Exhibit 2-AB: How was Welded Pipe Entered as Seamless in the Records]
[Exhibit 2-E: Former PG&E employee photograph near rupture area]
[Exhibit 2-F: PG&E retiree interview]

[Exhibit BW: City of San Bruno Sewage Contractor Ornelas interview]
[Exhibit 2BY: PG&E Excavation Inspector Paolo interview]

I. Milpitas Terminal

The Milpitas terminal is the first station at the southernmost point of Line 132. This unmanned station is comprised of four incoming lines with Maximum Operating Pressures from 477 to 600 psig and five pressure-regulated outgoing lines with varying MOPs of 200 to 375 psig. The specific lines and pressures are listed in tables 1 and 2[25].

[24] Underground Service Alert
[25] Line numbers, diameters and operating pressures as indicated on the Milpitas terminal single line drawing

***Incoming* Lines at Milpitas Station**

Line #	Dia. inches	MAOP psig	MOP psig
107	36	720	477
131	30	595	590
300A	34	558	558
300B	34	600	600

***Outgoing* Lines at Milpitas Station**

Line #	Dia. inches	MAOP psig	MOP psig
132	24	400	375
101	36	400	375
109	24	375	375
100	20	400	375
0805	24	200	200

Within the Milpitas terminal, the incoming lines are routed through a mixer/separator and several common manifolds before splitting out into multiple regulating sets. The Milpitas station includes a 20-inch diameter mixer bypass line with a regulator (valve 29) and monitor (valve 28) as well as a 24inch diameter station bypass line that connects the 300A and 300B incoming line into the outgoing lines.

Each of the four incoming lines is pressure controlled through two sets of regulators, where each set consists of a trim and load control valve preceded by a monitor valve upstream. Every set of regulators or control valves are arranged in parallel with a full line sized valve acting as the load valve and a valve half the line size acting as the trim valve. Each of the 26 regulating control valves is managed through an independent Siemens 353 controller connected to the Station PLC. The trim valve operates as the primary means of regulation during periods of low demand and the load valve operates when the corresponding trimmer valve is below 20% or above 80% open.

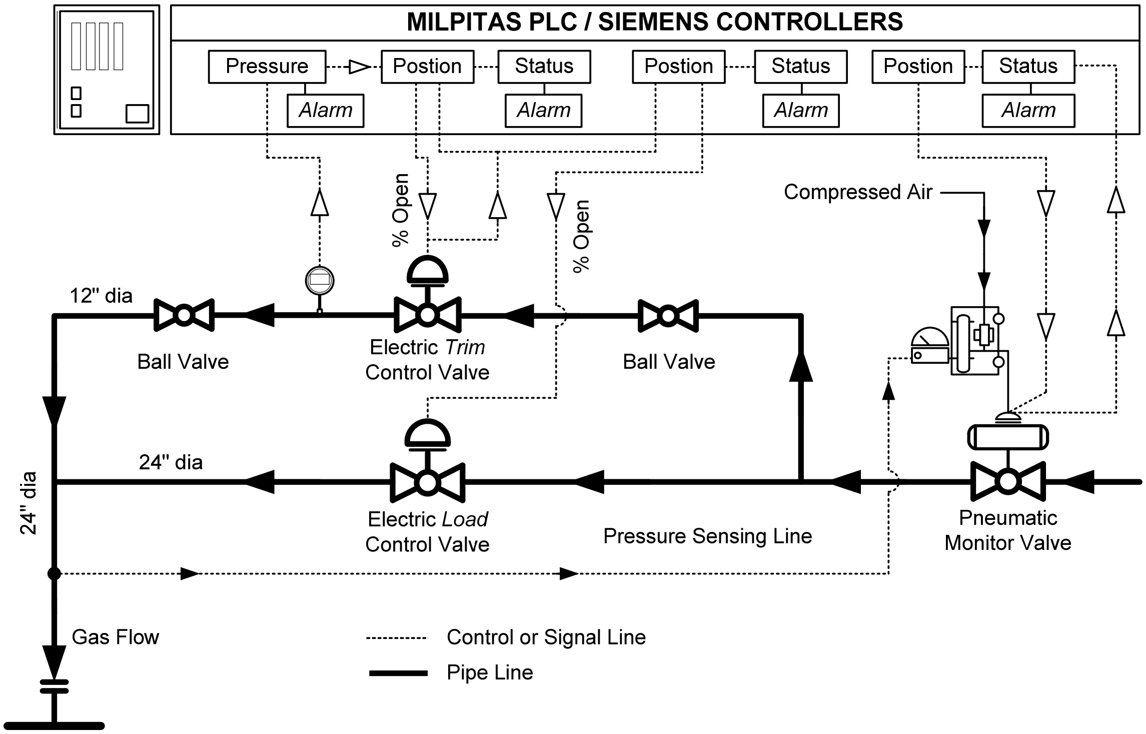

Figure 3: Typical Regulating valve with Monitor Valve and Controls

The load and trim valves are electrically actuated with a 3-phase 240v motor which is modulated from a 4-20mA signal. The control valves will fail in last-state on loss of power and fail open on loss of control signal. The regulating valves may be placed in manual operation at the controller, located in the Milpitas Terminal. In manual mode, the set point will track the actual pressure and disable the gas system operator's ability to command the valve.

In order to further protect the outgoing transmission lines from seeing pressures above their established MOP, there is a monitor valve installed on each of the lines. The monitor valve is a stand-alone pneumatically actuated control valve with a Bristol pneumatic PID[26] controller and limit switches wired back to the PLC. The monitor valve is given a set point locally at the controller, but is set to a pressure higher than the regulating valves but below the MAOP. The gas system operator can limit the percent open on a monitor valve but is not capable of overriding the local pressure set point at the pneumatic controller. The monitor valve is normally wide open and will only begin to control when downstream pressures, read through a sensing line connected to the pipeline, exceed its set point. In the case of Line 132, the monitor valves at Milpitas Station for Header 1, to which Line 132 is connected, are set at a pressure of 386 psig.

[26] Proportional Integral and Derivative control.

J. SCADA System and Operations

The PG&E gas control center is located at PG&E's headquarters in downtown San Francisco. The control center manages the operations of PG&E's entire gas transmission pipeline system including terminals and regulating stations through the SCADA system. The gas control center is instrumental in controlling gas deliveries throughout PG&E's system. The control center is staffed by three gas system operators working a 6:00 am to 6:00 pm shift and two operators on the evening shift from 6 pm to 6 am. The gas system operators manage alarms and control set-points, as well as perform field coordination of work taking place on clearances on the various pipelines. Also on each shift, alongside the gas control system operator, are a gas coordinator and senior gas coordinator.

The pipeline modeling group within the engineering division is also available to the control center staff for technical assistance. The modeling group maintains a hydraulic model of the PG&E pipeline system that can be used as a diagnostic and analytical tool for identifying operational problems. The PG&E pipeline modeling group also utilizes Pipeline Manager flow-modeling software for planning purposes but does not utilize the real-time leak detection capabilities when coupled with SCADA system.

The gas control operators are not assigned specific regions on the pipeline; rather, all gas system operators oversee all transmission line operations. Therefore, the operator that acknowledges an alarm may not be the same operator working with the field personnel that generated the alarm. And an operator that started as the point of contact for field operations may not be the operator that answers the telephone when there are further questions from the field. All of the operators sit next to one another in a common area of the control center that facilitates communications between one another.

PG&E uses a Windows© based SCADA software, Citect, with GE Fanuc Series 90-30 redundant PLCs at the Milpitas terminal. Thus there is some SCADA equipment at Milpitas to allow monitoring by Milpitas staff, but changes are made by Gas Control in San Francisco. The control center has fully redundant computers and workstations in an alternate location (Brentwood facility) for use during emergencies. PG&E conducts drills quarterly over a 3-4 day period to ensure that the redundant location is fully functional. September 9th, 2010 was supposed to have been the quarterly test of the alternate Gas Control Center. Gas control staff was setting up the alternate Gas Control Center for eventual transfer that evening. Controllers moved to the alternate location that day and were able to start up the consoles and watch the line operation; however, after the events of the evening hours of September 9th, the decision was made to keep the control center based in San Francisco.

The SCADA system operates on a 45 second scan rate to the field devices. The line pressure is managed by the gas operators through set point changes to the various terminals and regulating stations along the transmission line. Most often the set point changes are pressure based to the station control valves or regulators; however, the gas system operator has the option of using flow control as well. A set point change by the gas system operator is made to the regulators at the station either as a percent open command to the valve or as a downstream pressure setting. The SCADA software prevents the operator from entering a pressure that exceeds the MOP of the pipeline and high-high and low-low alarms act as another control to alert the operators when abnormal pressures are above pre-established values. The high-high and low-low alarms cannot be changed by the operator; however, the operators do have the ability to set the low and high alarms on the on the field device per the alarm settings panel in Citect. The use of low and high alarms provides more immediate feedback to the operator of the load conditions on the pipeline.

The gas system operators have several screens for controlling the system starting with the entire peninsula system with GIS overlay showing flows and pressures at key terminals. From there the gas system operator can select a specific region which will show a smaller geographical area in greater detail with cross connects, pressure, flows and valve status in that area. The gas system operators are also capable of overseeing any terminal or regulating station by clicking on the station or using a drop down menu. From there they can make changes to set points to the specific station valves as well as watch the incoming and outgoing line pressures and flows.

There is a single alarm screen that receives alarms for the entire system with both audio and visual indicators made to the operator. The alarms appear in chronological order and are color coded by severity. Red are the most critical alarms followed by orange and yellow in decreasing severity. Notifications and acknowledged alarms appear in black text on a white background. The SCADA point gets a red background on the on-line displays when it has entered in to an alarm condition as another indicator to the operator. The operator does have the ability to disable alarms. Disabled alarms appear on a separate “disabled alarm” screen that can be accessed up from the drop down alarm menu. Within SCADA the displays for valves are color coded to provide the gas system operator with feedback on the status. Red valves on the display denote “open valves” and green valves indicated “closed valves”. Valves that show up as yellow are modulating valves controlling to a set point pressure or flow. A small black dot centered on the valve graphic indicates to the controller that the valve is controllable. SCADA trends and attributes for a specific tag-name are easily pulled up by clicking on the points. Overlay trends can be generated from the trend screen by importing other tag names into an existing trend window.

From the control center in San Francisco the gas system operator can see the status of the control valves at the Milpitas terminal as an actual percentage of full flow the valves are open. This enables the gas system operator to throttle valves to reduce or increase pressure as needed. The gas system operator can monitor the pressures and flow rates of each transmission pipeline terminating or originating at the Milpitas terminal. Furthermore, the gas system operator can see the status of the monitoring valves and can limit the percentage that monitor valves are open. The gas system operator cannot make changes to the operating pressure of the monitoring valves which is set locally at the pneumatic controller. In addition to the control valve redundancy and monitor valve fail safe, the Milpitas station is outfitted with twin generators and a UPS (Uninterruptible Power Supply) to maintain power to the PLC, chromatographs, instruments, controllers and compressed air compressors in the event of a loss of normal power.

[Exhibit 2H: SCADA Screenshot of Peninsula System and Milpitas to Martin Terminal]
[Exhibit 2J: SCADA Alarm Policy]
[Exhibit 2V: SCADA and Controls Group Supervising Engineer]

K. Risk Management and Integrity Management

PG&E's Gas Transmission Integrity Management Program (IMP) is set forth in Risk Management Plan Six (RMP-06), which is one of the eleven chapters concerning PG&E's risk management plan. RMP-06 is designed to provide the best methods and implementation to ensure the safety of gas transmission pipelines located where a leak or rupture could do the most harm, defined as High Consequence Areas (HCA's). This procedure is the controlling document for the Gas Transmission Integrity Management Program.

In October of 2001 PG&E developed a Risk Management Plan (RMP-01) procedure designed to provide a process for maintaining the California Public Utility Commission's (CPUC) California Gas Transmission Risk Management plan. The entire PG&E risk management plan including the section on integrity management plan is required to be reviewed yearly. The plan was amended in 2003, twice in 2004 and twice in 2005. The plan is reviewed yearly but if there are no changes there will not be a notation on the plan's revision history. The plan states PG&E will conduct an inventory of all the pipeline design attributes, operating conditions, environment (e.g. structure, faults, etc) threats to the structural integrity, leak experience, and inspection findings must be developed and maintained. PG&E uses a GIS mapping database as the system of record for class locations and identification of HCA's. The HCA's are defined using the Potential Impact Circle (PIC) method, which designates an HCA by whether a 600 foot radius circle contains 20 or more dwellings. If it does, the area is classified an HCA regardless of class designation. The original job files are the system of record for pipeline parameters and specifications including pipe size, fittings, seam type and maximum allowable operating pressure (MAOP) pressure ratings. The two factors used to calculate the PIC are pipe diameter and MAOP. The MAOP of line 132 was determined using the method described in 49CFR

§192.619 (see Section M of this report for further information on the requirements for determining MAOP).

[Exhibit 2-AU: PG&E Integrity Management Plan Excerpts]
[Exhibit 2-AV: PG&E Risk Management Plan Excerpts]

PG&E developed individual risk management plans to deal with each of the perceived threats to their system. RMP– 02 contains an algorithm to calculate the risk to the PG&E system of external corrosion. RMP-02 was developed in 2001 and has been amended in 2003, twice in 2005, 2006, and 2010. It details possible threats to the pipeline caused by items such as soil resistivity, coating age, coating design, and dc/ac interference. It allows for the results of pressure tests, visual inspections of the coating, casing surveys, corrosion leak rate, and External Corrosion Direct Assessment (ECDA)[27] data, if available to develop a ranking of coated piping.

RMP-03 contains the third party threat algorithm. It was developed in 2001 and revised in 2003, twice in 2005, in 2008 and 2009. It weights the likelihood of excavation frequency, class location, ground cover protection, third party damage prevention, pipe diameter, and wall thickness, among other factors, to rank the vulnerability of pipelines to third party threats.

RMP-04 contains the ground movement and natural forces threat algorithm. It was developed in 2001 and amended in 2004, 2005, 2007, 2008, and 2009.

RMP-05 contains the design/materials threat algorithm; this was developed in 2001, amended in 2003, twice in 2005, and 2009.

PG&E developed RMP-06 the Gas Transmission Integrity Management Program to meet the requirements of 49CFR 192 Subpart O. This subpart describes all of the elements needed in an integrity management plan for a transmission pipeline and lists numerous risks to the integrity of the pipeline system the plan must cover. The plan was implemented in December of 2004 and amended in 2005, 2007, 2008, and 2010.

PG&E's base line assessment plan[28] includes 1021 miles of High Consequence Areas and approximately 500 miles of non-HCA pipeline. Of the 1021 miles to be assessed by December 17, 2017:

- 813 HCA miles will be assessed using direct assessment methodologies (External Corrosion Direct Assessment, Internal

[27] ECDA is a method where a pipeline is surveyed electrically in two directions and likely areas of potential corrosion are selected. These areas are then excavated and physically examined for corrosion.
[28] The base line assessment plan is the initial evaluation of the condition of the pipeline that will be used as a baseline for further inspections.

Corrosion Direct Assessment, and Stress Corrosion Cracking Direct Assessment).

- 208 miles of HCA miles will be assessed using In-Line Inspection tools.
- 500 miles of non-HCA will be assessed using In-Line Inspection tools.

PG&E's Integrity Management Plan (RMP-06) Section 2.4 "Gather data" reads "comprehensive pipeline and facility knowledge are essential to understanding the risk drivers that can affect an HCA." Page 59 of the Integrity Management Plan states: "the company shall consider the addition of automatic shut-off valves (ASV) or remote control valves (RSV) if they would be an efficient means of adding protection to an HCA." A senior consulting gas engineer commented in a letter dated June 14, 2006 to Risk Management file 8.10, the company had concluded that: "in most cases, the use of ASV's or RCV's as a preventative and mitigation measure in a HCA has little or no effect in increasing human safety or protecting pipelines".

[Exhibit 2-Q: Senior Consulting Engineer memo to file and supporting documents]

PG&E uses Method 2, the Potential Impact Circle method, described in CFR §192.903 to determine HCAs. To determine class locations PG&E follows the requirements stated in 49 CFR §192.5 which are based on the number of dwellings in the class area. Line 132 from milepost 8.39 to milepost 40.08, which includes the location of the rupture, is specified as a Class 3[29] location according to the PG&E documentation provided to the NTSB.

[Exhibit 2-R: 49CFR §192.903]
[Exhibit 2-S: PG&E PIR & HCA Drawings]

The PG&E corrosion control program with respect to Line 132, pipe –to-soil reads are conducted every other month and rectifier reads are obtained annually for external corrosion control monitoring. There was no visible evidence of external or internal corrosion or stress corrosion cracking on the Line 132 sections examined by the NTSB Materials Laboratory.[30] The available tools under the 49CFR192 code for inspection of Line 132 were ECDA, Inline Inspection (ILI) or hydrostatic testing. Unfortunately the bends and changes in diameter made ILI impossible for Line 132 so PG&E opted to use ECDA to assess the corrosion and coating of a section of line 132 in 2005 and 2009.

[29] Class location is defined in 49 CFR 192.5 and it refers to the number of buildings in an area that is 220 yards on either side of the centerline of a continuous one mile length of pipeline. Class 1 has 10 or fewer buildings, Class 2 has 10 to 46 buildings, Class 3 has 46 or more buildings and Class 4 has buildings 4 or more stories that are prevalent.

[30] For further details see the Metallurgical Group Chairman's factual report.

PG&E conducts a stress corrosion cracking direct assessment (SCC) detection process at every ECDA excavation that it performs. A supervising engineer in the transmission integrity management group stated that PG&E inspections for SCC have revealed no stress corrosion cracking in its pipelines since 2003.

[Exhibit 2-T: Standard Cathodic Maintenance Report]

The inline inspection program is listed as Risk Management Plan (RMP-11). PG&E has conducted in-line inspections on some of their gas transmission pipelines. PG&E used two types of General Electric PII® tools (smart pigs) which work on the principle of magnetic flux leakage. The first tool is used to evaluate circumferential defects and the second tool is designed to locate longitudinal defects. At the time of the accident no inline inspections had been performed on lines 101, 109 and 132 along PG&E's Peninsula gas transmission system. PG&E indicated that bends, plug valves or other incompatible valves as well as variations in pipe diameter were reasons for not having performed ILI on these lines. In its 2011-2012 gas rate case PG&E has requested permission to replace sections and/or fittings on the lines that currently prevent lines 101, 109 and 132 from accepting smart tools.

[Exhibit 2-U: Interview with Supervising Engineer for ILI and DA Programs]

L. Post Accident Actions

PG&E

Subsequent to the accident, PG&E performed testing at Milpitas station to determine the cause of the power failure to the station SCADA system sensors. The Milpitas station supervisor stated during a January 4, 2011 interview with NTSB investigators it was his conclusion that someone either had opened an electric breaker that was to remain closed or there was a power supply failure of both 24vdc power supplies at the same time. A test conducted by PG&E personnel of one of the power supplies revealed it to be inoperative; the test of the other power supply indicated an output of less than the rated 24vdc. Both power supplies have been replaced.

[Exhibit 2-V: Milpitas Station SCADA and Controls Group Supervising Engineer Interview]

Following the San Bruno accident PG&E modified its website such that interested persons can determine the location of gas transmission lines relative to any address. The web pages also provide safety information related to gas transmission systems, as well as material regarding the resources PG&E has made available to support San Bruno's residents and the rebuilding process. In addition, on October 12, 2010, PG&E announced its Pipeline 2020 program, which is designed to improve the safety of PG&E's natural gas transmission system by modernizing critical pipeline infrastructure, expanding the use of automatic or remotely operated shut-off valves, developing improved pipeline inspection technologies and best practices, and enhancing partnerships with public safety agencies. PG&E announced that the company plans to file an outline of its Pipeline 2020 program with the CPUC during the first half of 2011. Lastly, PG&E has undertaken a review to validate its pipeline material records for the five transmission pipelines in the Peninsula transmission system.

[Exhibit 2 CM: Pipeline 2020 Program Announcement]

California Public Utilities Commission (CPUC)

On September 12, 2010 the CPUC ordered PG&E to undertake several actions; among them were to conduct leak surveys on all pipelines with priority to transmission lines in Class 3 and 4 areas, preserve all records, review PG&E's classification system, report on gas leak procedures, and to provide evidence to the CPUC and PHMSA that the pipeline records found are complete. The CPUC convened an expert panel to assist in their investigation.

On September 13, 2010 the CPUC ordered PG&E to take additional steps that included a 20 percent reduction in the pressure levels of Line 132, an integrity assessment of all gas facilities in the impacted area, conduct an accelerated leak survey of all transmission lines, obtain and evaluate records for accuracy, develop a safety inspection plan, preserve all records, review classifications of natural gas transmission lines, review valve locations, and identify locations where the use of automatic or remote shut-off valves would be prudent.

On December 16, 2010 the CPUC ordered PG&E to:

1. Reduce, to 20% below the MAOP for each pipeline, the maximum pressure on pipelines that have segments that have all of the following characteristics:
    a. All Class 3 & 4 pipelines and all Class 1 & 2 pipelines located in HCA's as defined by 49 CFR §192.3; and
    b. 30-inch diameter pipelines having Double Submerged Arc Welds or its manufacturing equivalent; and
    c. Installed prior to January 1, 1962, and having not undergone hydrostatic pressure testing or the equivalent.
2. PG&E shall assess the integrity of the pipelines described above, using one of the following four methods:
    a. Hydrostatic or other appropriate pressure test per 49 CFR 192, Subpart J; or
    b. X-ray; or
    c. A camera examination of the interior of the pipe; or

d. An inline inspection using a “smart pig” or other technology appropriate to assessing pipeline seam integrity.

On January 3, 2011 the CPUC ordered PG&E to comply with the NTSB’s urgent recommendations to PG&E.

[Exhibit 2-DN: CPUC Post Accident Responses to San Bruno Pipeline Explosion}
[Exhibit 2-DT: CPUC and PG&E Correspondence Regarding the San Bruno Accident since December 16, 2010]

M. <u>CPUC and PHMSA Oversight</u>

California Public Utilities Commission

In 2005 the CPUC conducted an Integrity Management Audit of PG&E in which PHMSA participated. This was intended as a training audit for the CPUC personnel. A few of the issues noted during the audit were resolved during or following the audit. Some of the issues were resolved through PG&E’s revisions to procedures in the 2005 PG&E Integrity management plan.

The PG&E integrity management plan (IMP) was audited again by the CPUC in May 2010 and findings sent to PG&E on October 21, 2010. The auditors identified two areas of concern; the first was that PG&E may be “diluting the requirements of the IMP through its exception process and appears to be allocating insufficient resources to carry out and complete assessments in a timely manner.” The second concern in the CPUC audit is that “PG&E needs to analyze, review, and formulate appropriate actions or responses to the results of its internal audits in a timely manner.” There were no notices of violation cited in the 2010 CPUC audit letter.

[Exhibit 2DO: Summary of CPUC 2005 IM Audit of PG&E]
[Exhibit 2DP: CPUC 2005 PG&E IM Audit Meeting Summary]
[Exhibit 2DH: PG&E Response to CPUC 2010 IM Inspection]
[Exhibit 2DI: PG&E Response to California Public Utilities Commission October 21, 2010 letter]
[Exhibit 2DJ: California Public Utilities Commission October 21, 2010 Letter to PG&E]

PHMSA

On August 19, 1970 federal pipeline safety regulations at 49 CFR §192.505 became effective. The amendments required a hydrostatic test for pipelines of 125% of MAOP for a minimum of 8 hours for newly constructed gas transmission pipelines. Pipelines constructed before 1970 were grandfathered and not required to be hydrostatically tested. The amendments allowed the MAOP for these older pipelines to be based the pipeline operating at that pressure. The governing code for determination of MAOP is 49 CFR §192.619.

§192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with Subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:

(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, _see_ § 192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or

(ii) If the pipe is 12¾ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa) gage.

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

	Factors[1], segment		
Class location	Installed before Nov. 12, 1970	Installed after Nov. 11, 1970	Covered under §192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

[1] For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006. —Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.	March 15, 2006, or date line becomes subject to this part, whichever is later.	5 years preceding applicable date in second column.
Offshore gathering lines.	July 1, 1976.	July 1, 1971.
All other pipelines.	July 1, 1970.	July 1, 1965.

The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).

The “Grandfather Clause” is found in §192.619(a)(3). It allows operators to continue operating natural gas pipelines at the highest pressure to which the pipeline had been subjected during the 5 years preceding July 1, 1970.

[Exhibit 2-CK – PHMSA Advisory Bulletin ADB 11-01]

List of Exhibits

1) Exhibit 2B: PG&E Event Timeline
2) Exhibit 2C: 49CFR619(a)(3) and PG&E Documentation (NTSB 011-001)
3) Exhibit 2D: Schematic Showing Relative Locations of Nearby Services and L132 in the Trench
4) Exhibit 2E: Former PG&E Employee Photograph Near Rupture Area
5) Exhibit 2F: PG&E Retiree Interview
6) Exhibit 2G: Milpitas Terminal One-Line
7) Exhibit 2H: SCADA Screenshot of Peninsula System & Milpitas to Martin & Milpitas Terminal
8) Exhibit 2I: SCADA Alarms (NTSB 0014-008)
9) Exhibit 2J: SCADA Alarm Policy
10) Exhibit 2K: SCADA Pressure Readings on 9-9-10 (16:12 Through 18:42)
11) Exhibit 2L: Photo of Monitor Valve Pneumatic Controller
12) Exhibit 2M: PG&E Pressure Transducer Locations Along Lines 101,109, and 132
13) Exhibit 2N: PG&E SCADA Trends from 9-9-10
14) Exhibit 2P: PG&E Survey Sheets of Line 132
15) Exhibit 2Q: Senior Consulting Engineer MEMO to File and Supporting Documents
16) Exhibit 2R: 49CFR §192.903
17) Exhibit 2S: PG&E PIR and HCA Drawings
18) Exhibit 2T: Standard Cathodic Maintenance Report
19) Exhibit 2U: Supervising Engineer for the ILI and DA Programs
20) Exhibit 2V: SCADA and Controls Group Supervising Engineer
21) Exhibit 2-Y: San Francisco Control Room Transcripts
22) Exhibit 2-AB: How was Welded Pipe Entered as Seamless in the Records
23) Exhibit 2-AP: GM 151181 and 1961 L-132 Relocation Project Documentation
24) Exhibit 2-AU: PG&E Integrity Management Plan Excerpts
25) Exhibit 2-AV: PG&E Risk Management Plan Excerpts
26) Exhibit 2-AP: GM 151181 and 1961 L-132 Relocation Project Documentation
27) Exhibit 2BW: City of San Bruno Sewage Contractor Ornelas interview
28) Exhibit 2BY: PG&E Excavation Inspector Paolo interview
29) Exhibit 2-DF : Gas Distribution and Construction Superintendent Interview
30) Exhibit 2BV: Gas Controller Interview
31) Exhibit 2-CK: PHMSA Advisory Bulletin ADB-11-01
32) Exhibit 2-CM: Pipeline 2020 Program Announcement
33) Exhibit 2-DN: CPUC Post Accident Responses to San Bruno Pipeline Explosion
34) Exhibit 2-DT: CPUC and PG&E Correspondence Regarding the San Bruno Accident since December 16, 2010
35) Exhibit 2-DO: Summary of CPUC 2005 IM Audit of PG&E
36) Exhibit 2-DP: CPUC 2005 PG&E IM Audit Meeting Summary

37) Exhibit 2-DH: PG&E Response to CPUC 2010 IM Inspection