2012 Northeast Corrosion Conference – Springfield, Massachusetts
San Bruno, CA – Lessons Learned & Recent Legislation

Randy Knepper
Director of Safety
New Hampshire Public Utilities Commission

 Jan 18th, 2012

The Impact of 2010 and 2011

- Terrible years with high profile Incidents & Accidents
- **Deepwater Horizon, Gulf of Mexic**o
- **Marshal, Michigan (Federally Regulated)**
  – Major Crude Oil Spill Dramatically Impacted Several Communities
- **Romeoville, Illinois**
  - Followed Closely on the Heels of Marshal
- **San Bruno, California (State Regulated)**
  – Major tragedy – Unimaginable Proportions
- **Philadelphia, Pennsylvania (State Regulated**)
  Utility employee fatality
- **Allentown, Pennsylvania (State Regulated)**
  – Major tragedy – causes still being investigated
- **Hanoverton, Columbiana County, OH (Federally Regulated)**
  – Large Release of Gas of Interstate Pipeline
- **Yellow Creek Oil Spill, Montana (Federally Regulated)**

Topics

- **Impact of the San Bruno Explosion (Overview)**
- Explosion Images
- Ruptured Segment – Determination of Root Cause
- IMP Risk Ranking
- NTSB Findings
- Response Times
- Legislative Implications

San Bruno, CA Overview

- **Worst Gas Pipeline Incident to occur within last 25 years**
- **8 Fatalities including employee (and daughter) of the California Public Utilities Commission**
- **10 people sustained serious injuries**
- **48 people sustained minor injuries**
- **38 homes destroyed**
- **Another 70 homes were damaged, 18 to the extent they were uninhabitable**

San Bruno, CA Overview

- **Estimated over $550 million in property damages and compensation losses**
- **Estimated over $450 million in projected transmission pipeline replacements**
- **Loss of Gas of 48 million cubic feet**
- **Required 600 Fire and EMT First Responders**
- **Required 300 Police First Responders**
- **Numerous agencies involved. Civil cases, criminal cases**

Class action lawsuits

- **National Media Attention**
- **State Legislature Action, Congressional Action**

Investigation Timeline

- **NTSB issued Preliminary Report of Facts Sept 2010 (3)**
- **CPUC hired independent review panel to evaluate state safety program, statutory recommendations and technical assessment of PG&E in regards to management and operations associated with the incident Sept 23, 2010**
- **NTSB issued 3 Urgent Recommendations Jan 3 2011**
- **NTSB issued Materials Lab Factual Report Jan 21, 2011 (77)**
- **NTSB held hearings in March 2011 (3 days)**

Investigation Timeline (cont'd)

- **INGAA issued Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of PG&E San Bruno Incident May 5, 2011 (55)**
- **CPUC Independent investigation issued final report June 8, 2011 (196)**
- **NTSB produced final report Sept 26, 2011 (140)**
- **Overland Audit of PGE Gas Transmission Expenditures 1996 -2010 issued Dec 30, 2011 (20)**
- **CPUC Staff produced final investigation report**

January 12, 2012 (171)

NTSB Preliminary Report

Sept 2010

National Transportation Safety Board
Washington, D.C. 20594

Preliminary Report

Accident No.:	DCA10MP008
Type of System:	30-inch natural gas transmission pipeline
Accident Type:	Pipeline rupture
Location:	San Bruno, CA
Date:	September 9, 2010
Time:	About 6:11 p.m., Pacific Daylight Time
Owner/Operator:	Pacific Gas & Electric Company
Fatalities/Injuries:	Eight fatalities, multiple injuries
Pipeline Pressure:	386 pounds per square inch gauge (psig) at the time of rupture
Quantity Released:	Approximately 47.6 million standard cubic feet (MMSCF)

On September 9, 2010, at approximately 6:11 p.m. Pacific Daylight Time[1], a 30-inch diameter 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. On September 10, the NTSB launched a team to California to investigate this tragedy. Vice Chairman Christopher Hart was the NTSB Board Member on scene in San Bruno.

The rupture on Line 132 occurred near mile post (MP) 39.33, at the intersection of Earl Avenue and Glenview Drive in the city of San Bruno. Approximately 47.6 million standard cubic feet (MMSCF) of natural gas was 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 away from the crater. The released natural gas was ignited sometime after the rupture; the resulting fire destroyed 37 homes and damaged 18. Eight people were killed, numerous individuals were injured, and many more were evacuated from the area.

The Incident Command was set up by the local fire department. The immediate response by local emergency responders, as well as three strategic drops of fire retardant and water by air, assisted in stopping the spread of the fire.

1: All times mentioned in this report refer to Pacific Daylight Time, unless otherwise specified.

Docket No. SA-534

Exhibit No. 3-A

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

Metallurgical Group Chairman
Factual Report

(77 Pages)

NATIONAL TRANSPORTATION SAFETY BOARD
Office of Research and Engineering
Materials Laboratory Division
Washington, D.C. 20594

January 21, 2011

MATERIALS LABORATORY FACTUAL REPORT — Report No. 10-119

A. ACCIDENT

Place	: San Bruno, CA
Date	: September 9, 2010
Vehicle	: Natural Gas Transmission Pipeline
NTSB No.	: DCA10MP008
Investigator	: Ravi Chhatre, RPH-20

B. COMPONENTS EXAMINED

Three pieces of 30 inch diameter pipe.

C. DETAILS OF THE EXAMINATION

From September 30, 2010 through October 8, 2010, a Metallurgical Group was convened at a facility in Ashburn, VA for the purpose of documenting and examining the ruptured pipeline pieces and determining which portions of the pipe should be removed for further examination at the Materials Laboratory in Washington, DC. Members of the group included:

1) Donald Kramer, Ph.D., Materials Engineer, NTSB
2) Ravindra Chhatre, Investigator in Charge, NTSB
3) Robert Fassett, Director – Integrity Management & Technical Services, PG&E
4) Joshua Johnson, P.E., Materials Engineer, PHMSA Office of Pipeline Safety
5) Sunil Shori, Utilities Engineer, State of California Public Utilities Commission
6) Paul Tibbals, P.E., Sr. Materials Technology Engineer, PG&E

C.1. DOCUMENTATION OF AS-RECEIVED CONDITION

The as-received pipe was comprised of eight lengths of pipe in three separate sections as illustrated by the schematic in figure 1 and the photographs in figures 2-5. 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 (commonly referred to as a joint[1]) as shown in figure 2. The center section was 27 foot – 8 inch at its longest point and was

[1] A joint is a single length of pipe, typically 20 feet or greater in length.

Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of PG&E San Bruno Incident

INGA

Table of Contents

Executive Summary
Facts Pertaining to the Original Construction as Documented ir
Key Findings
INGAA Analysis of Publicly Available Information
Possible Cause of the Final Failure of the Longitudinal Weld
Suggestions to NTSB that may clarify the root cause
INGAA Analysis of the Root Cause of the San Bruno Pipeline Ac
INGAA Analysis of NTSB Metallurgical Group Factual Repor
Strength of the Remaining Material in Pup #1 Long Seam
Fatigue Behavior of the Longitudinal Seam of Pup #1
INGAA Analysis of External Force Activating Defect on Pup #
Conclusions Based on INGAA Analysis
Appendices
Appendix A. Background Information
Pipeline Pup Configuration
Fabrication Details
Appendix B. Vintage Standards and Processes to Eliminate No
Quality Controls and Safety Redundancy
Natural Gas Transmission Pipeline Manufacturing
Construction of the Transmission Pipeline
Integrity Management Regulations
Pipeline Operating Conditions
Appendix C. Public Media Reports
Raising of the Operating Pressure on Pipeline Segment
Mechanical Damage of the Pipe Segment
Fatigue of the longitudinal weld on Pup #1
In-Line Inspection of the Pipeline Segment

Appendix D. Results of the NTSB Laboratory Factual Reports (Exhibit 458194 and Exhibit 459591) 47
Steel Chemistry 48
Yield Strength of Steel 48
Rolling Direction of the Pups 49
Girth Welding 49
Pressure Tests 50
Appendix F. Definitions of Terms 53

JACOBS Consultancy

Report of the Independent Review Panel
San Bruno Explosion

Prepared For
California Public Utilities Commission

June 8, 2011

Pacific Gas and Electric Company
Natural Gas Transmission Pipeline Rupture and Fire
San Bruno, California
September 9, 2010

Accident Report

NTSB/PAR-11/01
PB2011-916501

National Transportation Safety Board

Overland Consulting

Focused Audit of Pacific Gas & Electric Gas Transmission Pipeline Safety-Related Expenditures

For the Period
1996 to 2010

Submitted to:

California Public Utilities Commission
Consumer Protection and Safety Division

Submitted by:

Overland Consulting
11551 Ash Street, Suite 215
Leawood, KS 66211
(913) 599-3323

December 30, 2011

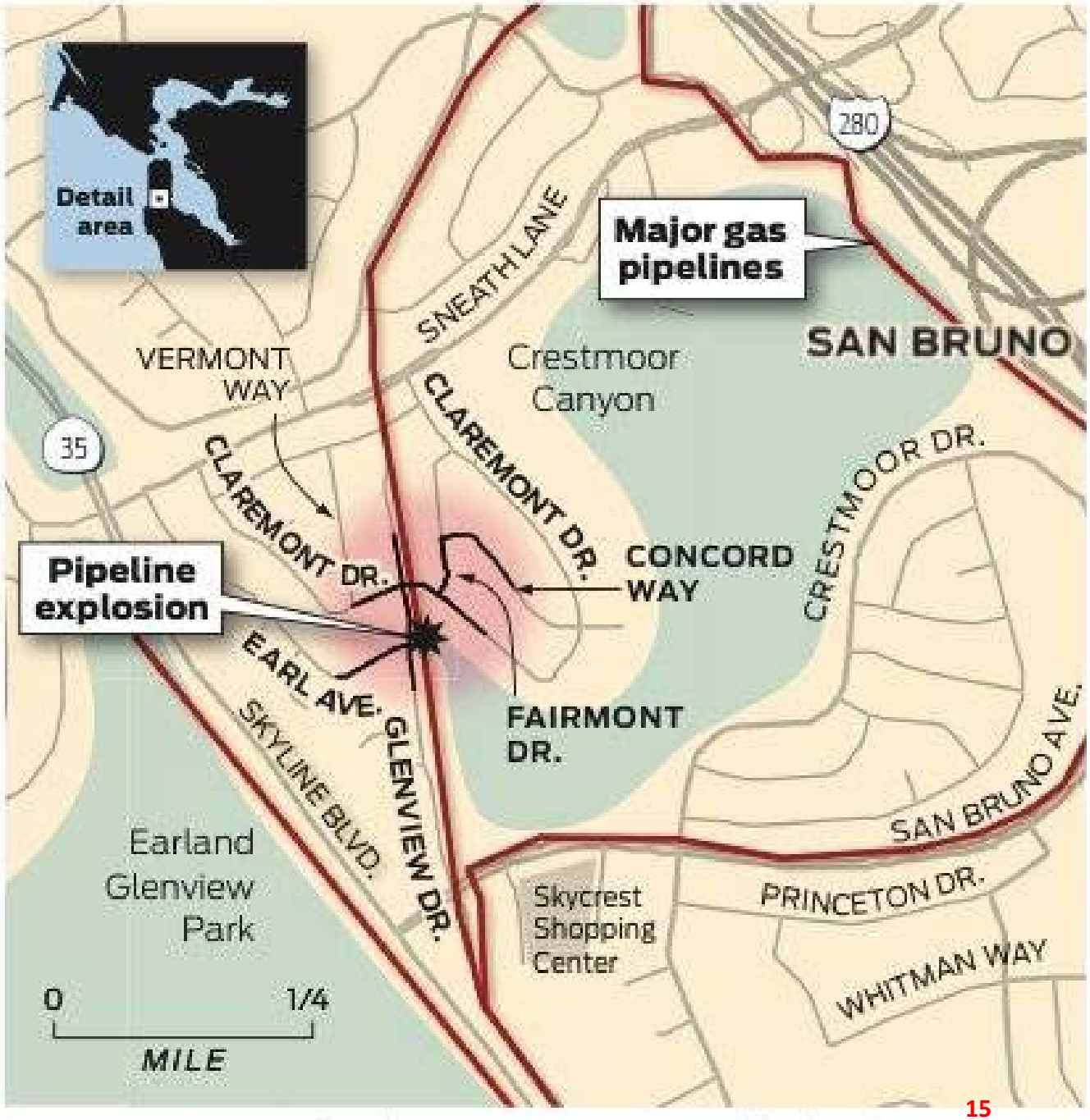
New Hampshire PUBLIC UTILITIES COMMISSION

CA PUC Consumer Protection and Safety Division Incident Investigation Report

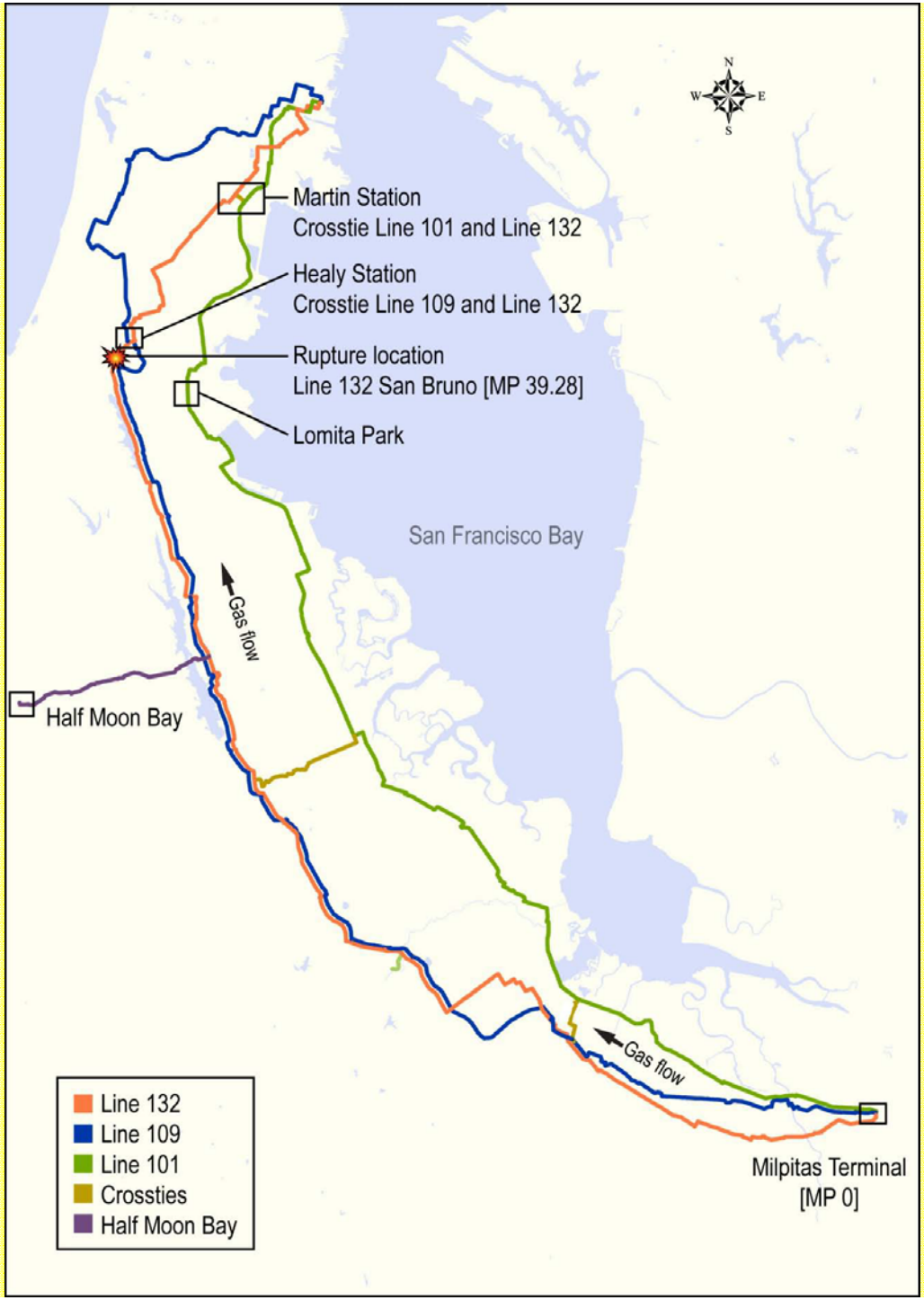
January 2012

San Bruno, CA
The Setting

- Sept 9, 2010
- 3 Intrastate Transmission Pipelines in area
- Operated by PG&E
- 30 inch diameter, .375 wall, API 5L X42
- Approx 400 psig
- Installed 1950's

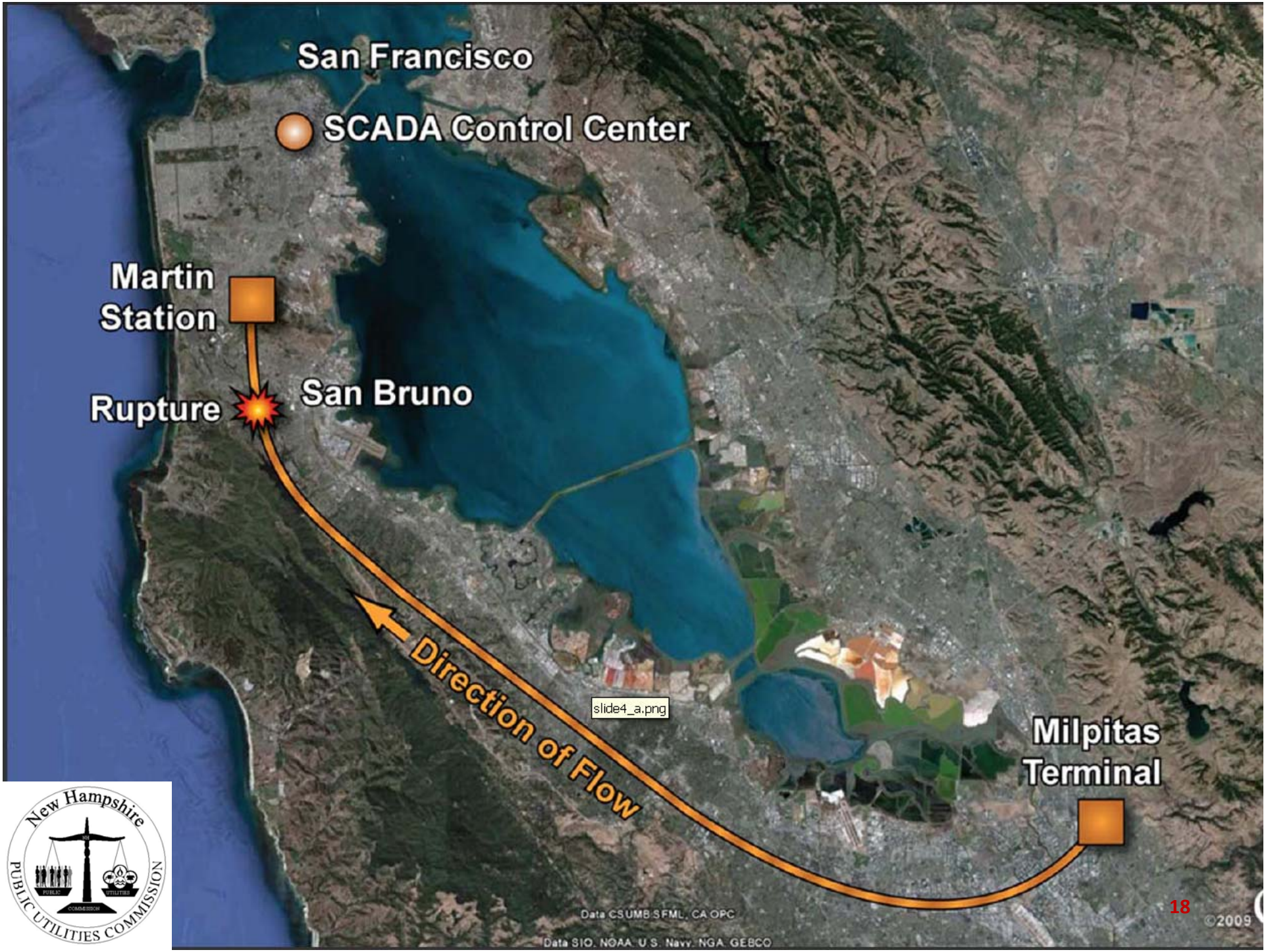


Sources: ESRI, gas pipeline by Rextag Strategies, neighborhood image by Picto


N
W
E
S
Martin Station
Crosstie Line 101 and Line 132
Healy Station
Crosstie Line 109 and Line 132
Rupture location
Line 132 San Bruno [MP 39.28]
Lomita Park
San Francisco Bay
Gas flow
Half Moon Bay
Gas flow
Line 132
Line 109
Line 101
Crossties
Half Moon Bay
Milpitas Terminal
[MP 0]

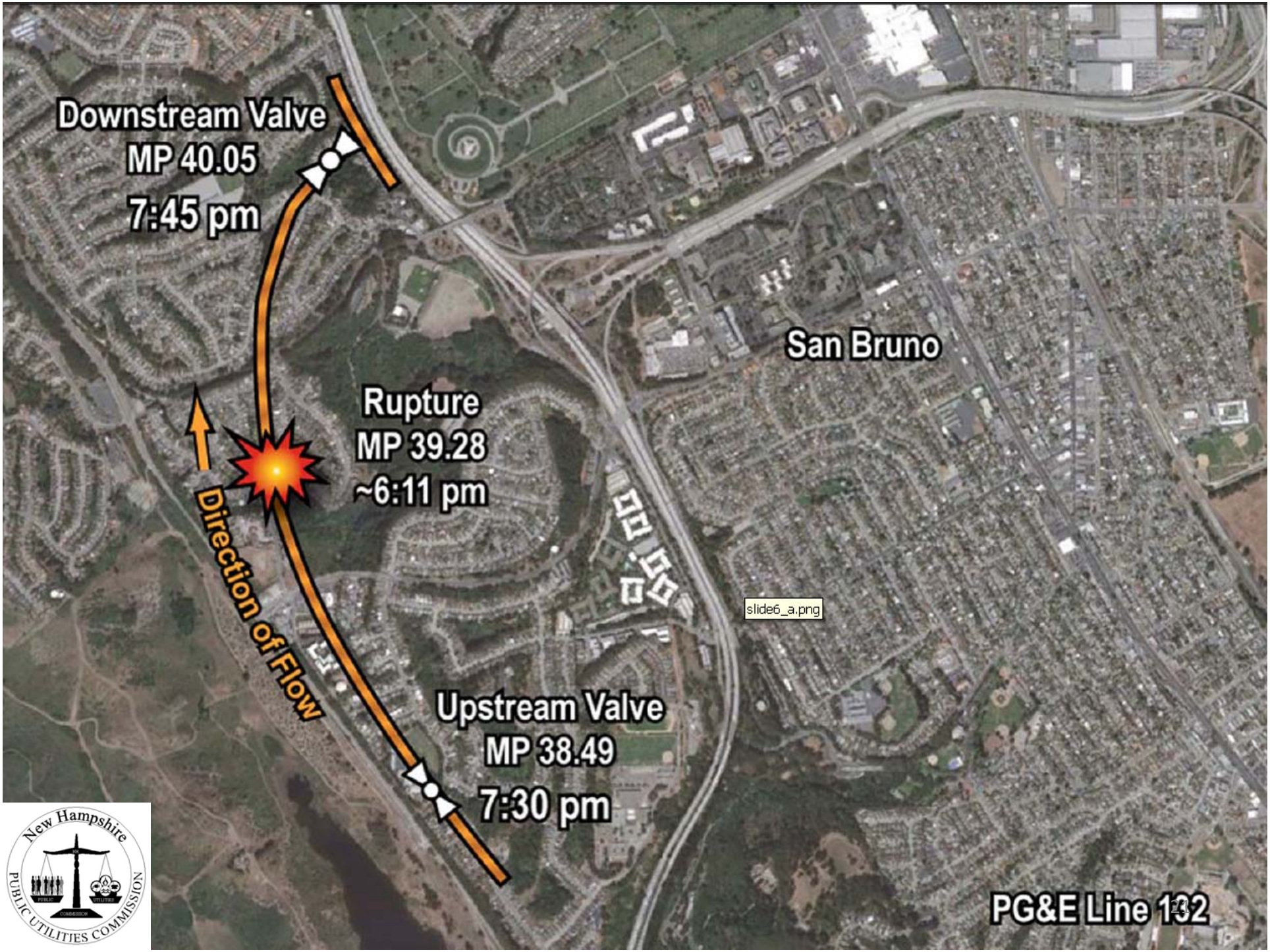
Topics

- Impact of the San Bruno Explosion (Overview)
- **Explosion Images**
- Ruptured Segment – Determination of Root Cause
- IMP Risk Ranking
- NTSB Findings
- Public Awareness
- Response Times
- Legislative Implications

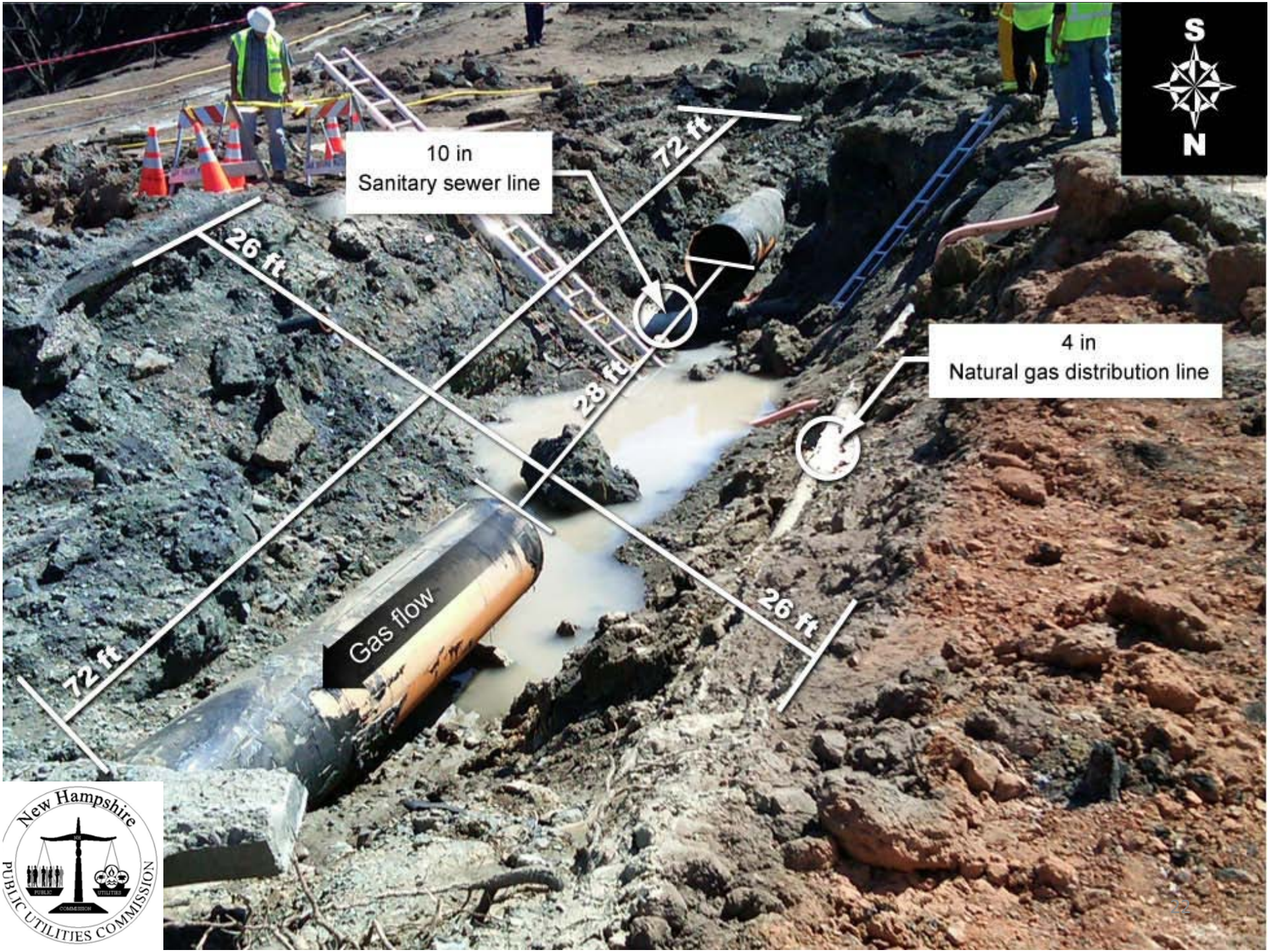

San Francisco
SCADA Control Center
Martin Station
Rupture
San Bruno
Direction of Flow
slide4_a.png
Milpitas Terminal
Data CSUMB SFML, CA OPC
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
©2009

slide2_a.png
Claremont Drive
Earl Avenue
RUPTURE
Glenview Drive
Destroyed (38)
Damaged (70)

San Bruno - The First Responders



New Hampshire Public Utilities Commission



New Hampshire Public Utilities Commission

San Bruno, CA – Ruptured Pipeline Section blown 100 feet from explosion site

San Bruno CA, - Devastated Neighborhood

San Bruno, CA –Aerial View Post Explosion

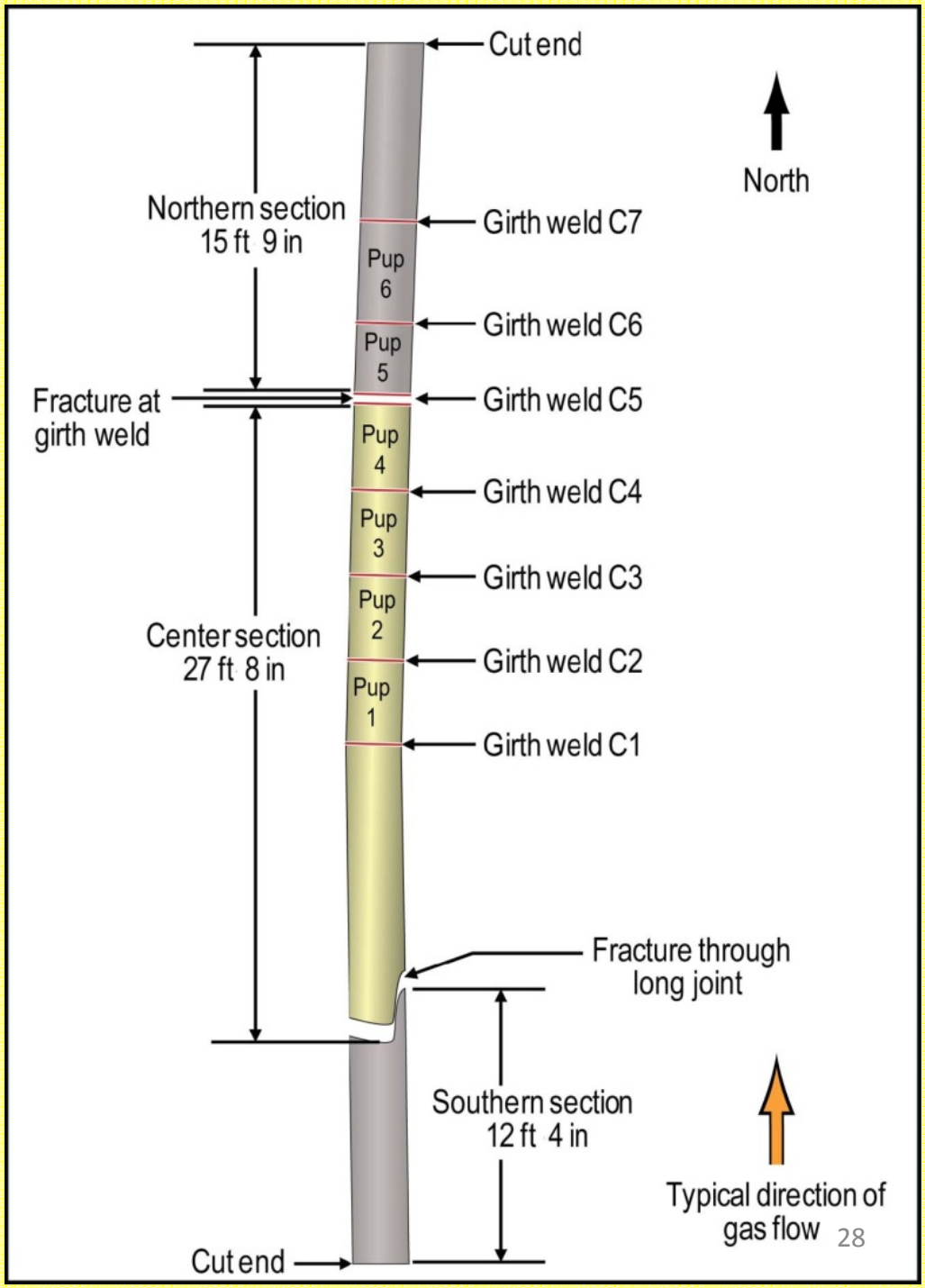
San Bruno, CA – Incinerated Remains of Vehicles

Topics

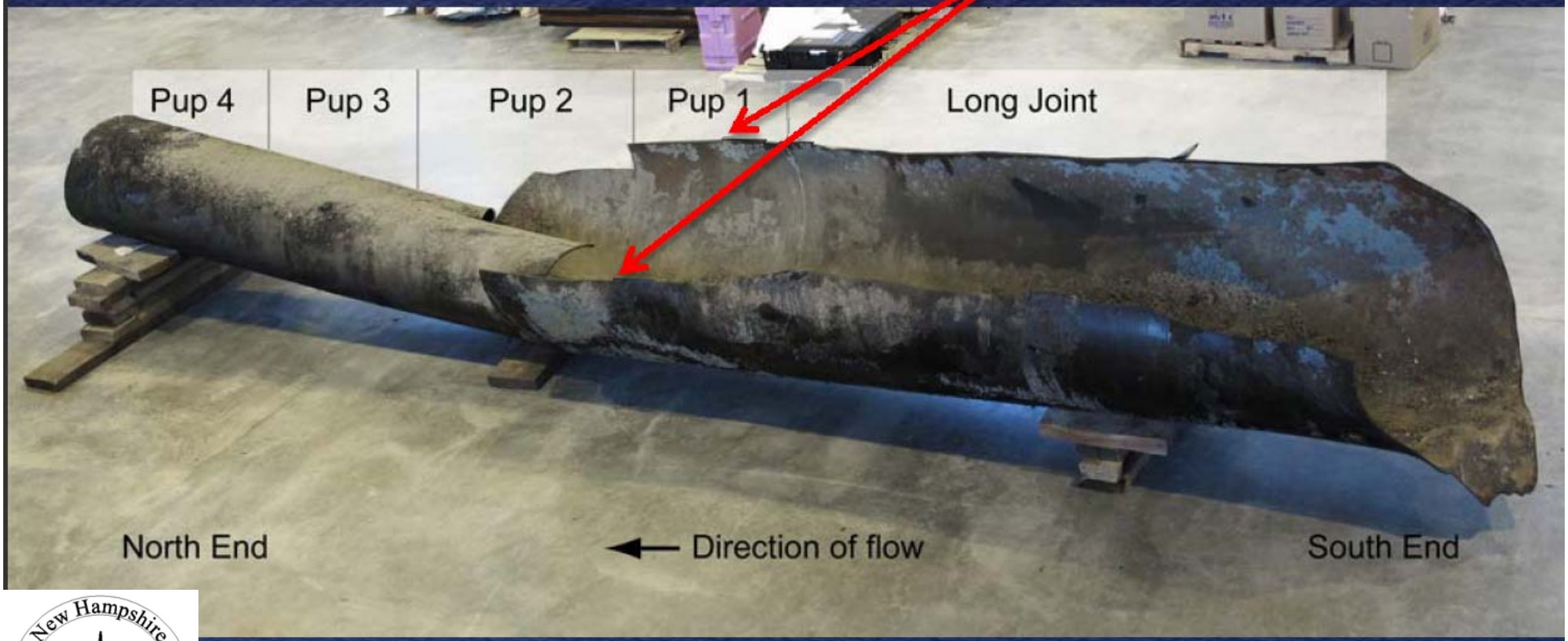
- Impact of the San Bruno Explosion (Overview)
- Explosion Images
- **Ruptured Segment – Determination of Root Cause**
- IMP Risk Ranking
- NTSB Results
- Response Times,
- Record Keeping
- Legislative Implications

Pipeline Segment that Failed

- Pup pieces were approximately 3.5 feet to 4 feet long (.375 in wall)
- 0.312 in wall at the north end



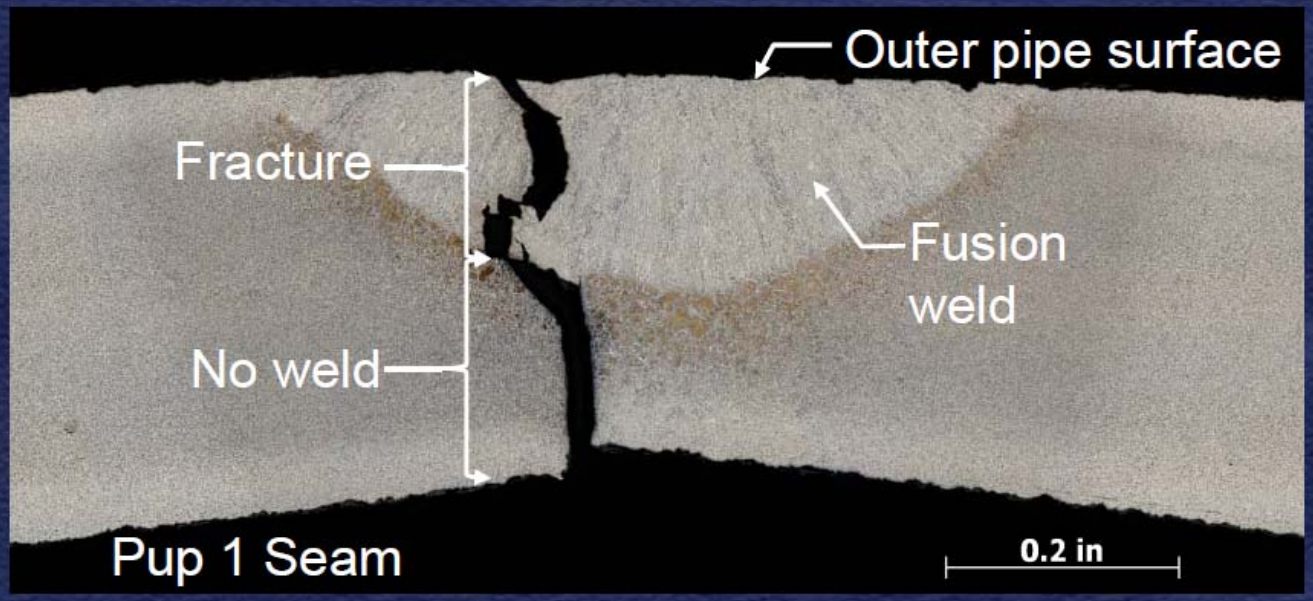
Ruptured Pipe Segment



Rupture Examination Welding

- Pup 1, Pup 2, Pup 3 had a seam weld
- A close examination of those welds compared to typical weld methods begin to reveal some clues
- The next slide is a closeup of Pup 1 Seam Weld
- While a typical DSAW weld is shown below

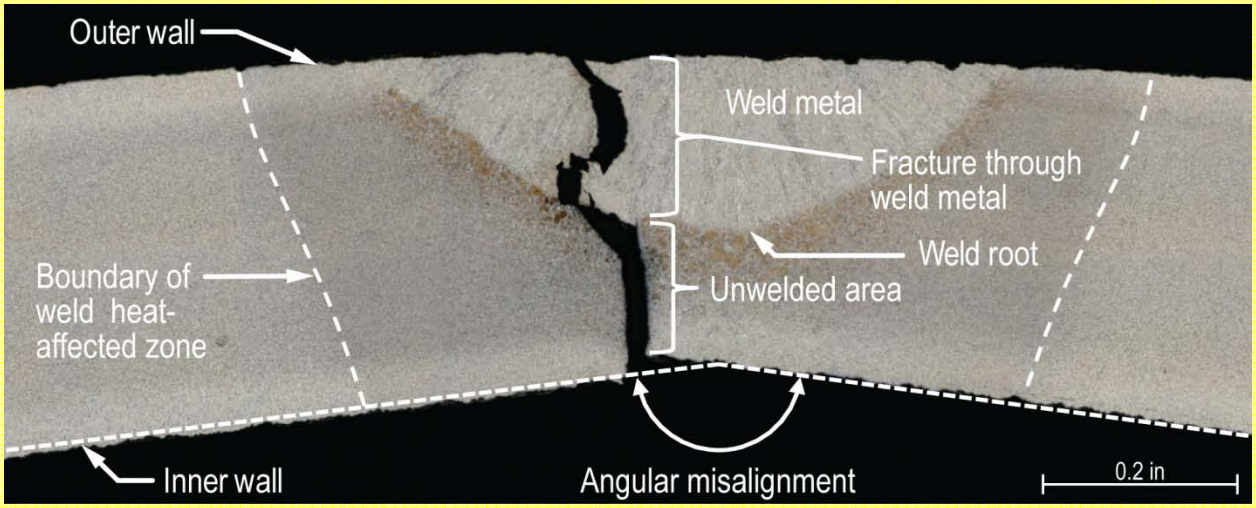
Cross Section of Pipe Seams

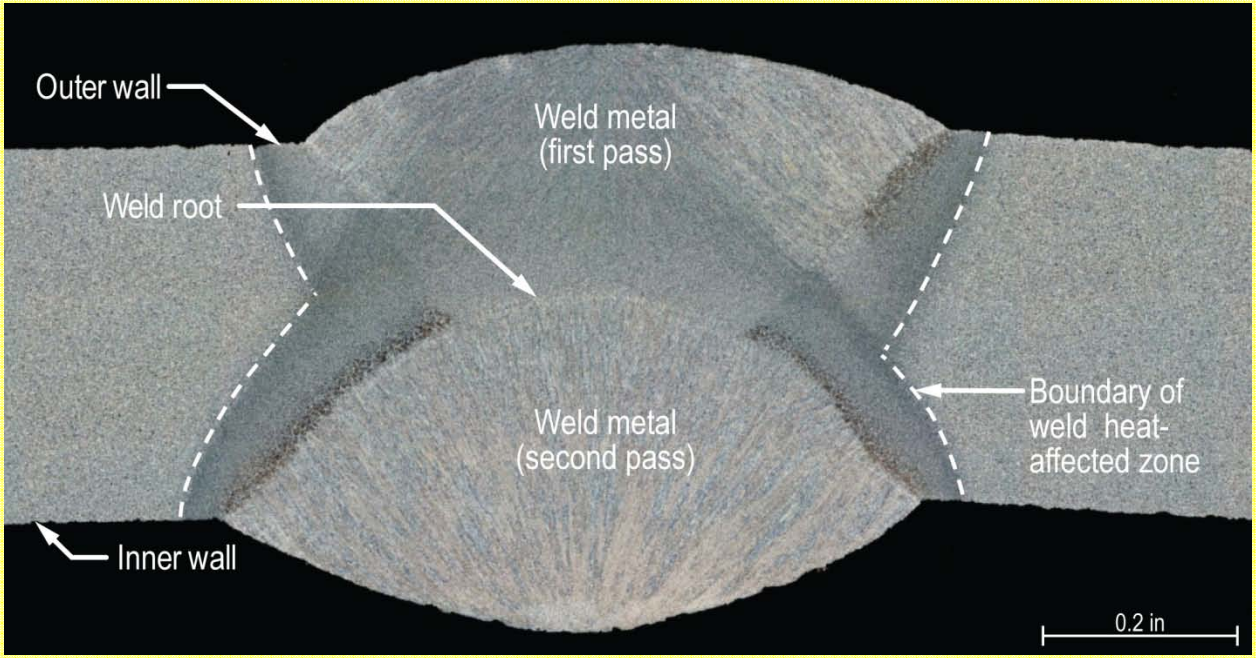


New Hampshire Public Utilities Commission

NTSB

Rupture Examination Welding

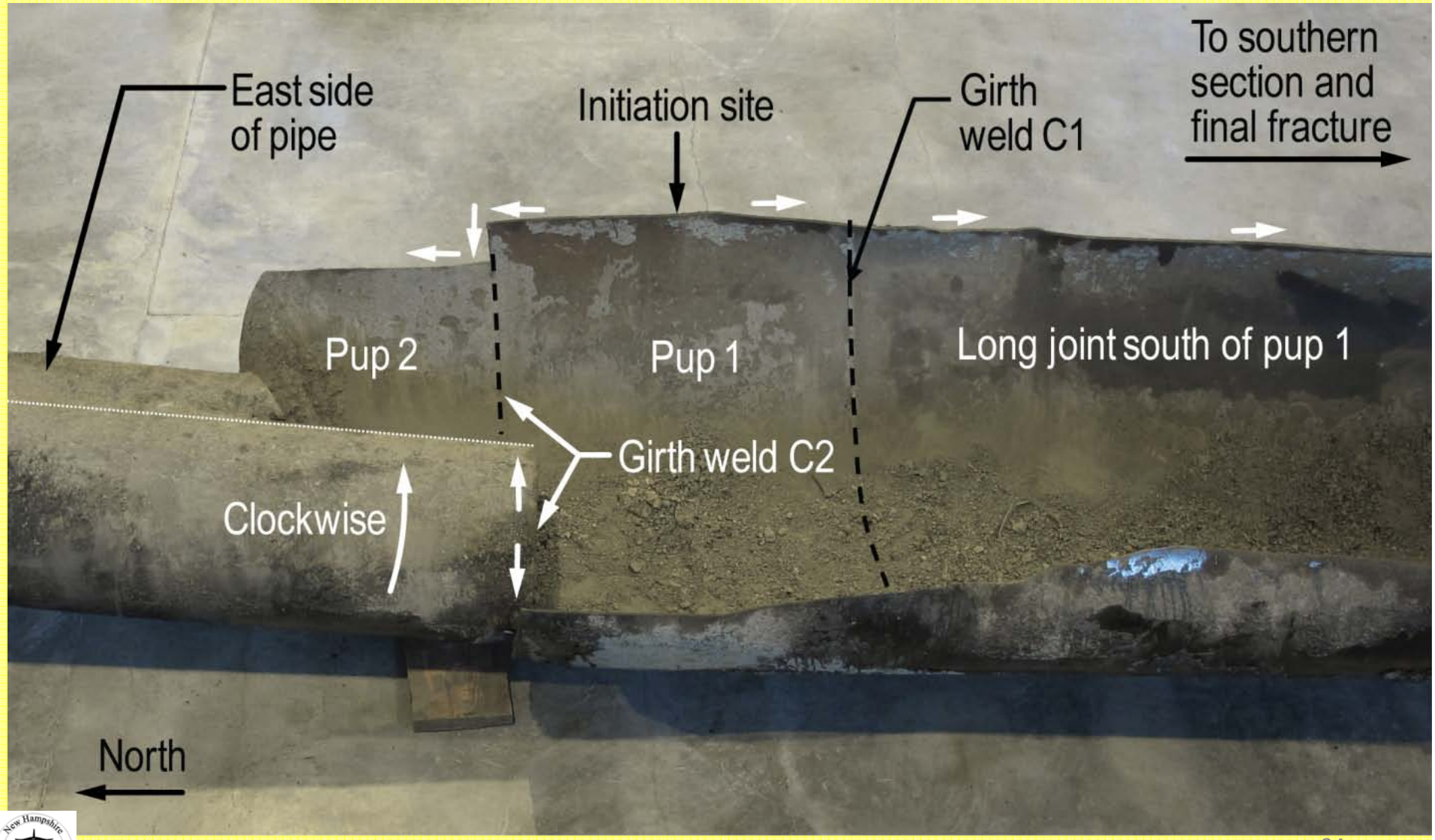




Rupture Examination Welding

- Welds showed indications of different Welding Methods such as Fusion Welding Process, Manual Arc Welding, Shielded Metal Arc Welding on Girth Welds (Field)
- Double Submerged Arc Welding (Factory)
- Evidence of Porosity, incomplete fusion, undercutting, Lack of Penetration, slag inclusion
- Squared Ends versus Beveled Ends

Location of Initiation of Cracks



Material Properties

- PG&E Pipe Spec use X42 SMYS or X52 SMYS

Specification	Minimum Yield Strength (ksi)	Minimum Tensile Strength (ksi)	Minimum Elongation (percent in 2 inch)
7R-61963 PG&E material specification	52.0	72.0	22
API 5LX X52, 1954	52.0	66.0	20
API 5LX X42, 1954	42.0	60.0	25

Sample	Yield Strength[a] (ksi[b])	Tensile Strength (ksi)	Elongation (percent in 2 inch)
South long joint	57.0 ± 0.6	83.2 ± 0.3	30.0 ± 0.7
Pup 1	36.6 ± 0.3	63.6 ± 0.2	39.4 ± 0.5
Pup 2	32.0 ± 0.1	52.0 ± 0.0	48.8 ± 0.8
Pup 3	34.9 ± 0.5	60.3 ± 0.3	42.8 ± 0.4
Pup 4	48.3 ± 0.5	79.0 ± 0.0	34.0 ± 0.7
Pup 5	38.5 ± 0.3	71.8 ± 0.3	35.8 ± 1.1
Pup 6	50.5 ± 1.4	78.7 ± 0.3	30.8 ± 0.8
North long joint	54.0 ± 0.4	76.9 ± 0.2	30.4 ± 0.5

Wait a second!!!

- I thought you said X42 or X52
- Do you mean you are not sure what type of pipe you used?
- Uh oh – I am beginning to wonder about Record Keeping.
- My Concern is now your concern!!!

Official Probable Cause

- NTSB determines that the probable cause of the accident was the Pacific Gas and Electric Company's (PG&E) (1) **inadequate quality assurance and quality control in 1956 during its Line 132 relocation project**, which allowed the **installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase** stemming from poorly planned electrical work at the Milpitas Terminal; ***and…..***

Topics

- Impact of the San Bruno Explosion (Overview)
- Explosion Images
- Ruptured Segment – Determination of Root Cause
- **IMP Risk Ranking**
- NTSB Results
- Emergency Response Times,
- Record Keeping
- Legislative Implications

Integrity Management Implications

- Part 192.917(e) addresses required actions for particular threats.
- It is one of the integrity management program rules that became effective in 2004
- One type of threat is manufacturing and construction defects
- Categorizes them into stable threats and instable threats

Integrity Management Implications

Manufacturing and construction defects. If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment.

Integrity Management Implications

An operator may consider manufacturing and construction related defects to be **stable defects** **if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area.** If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

- (i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;
- (ii) MAOP increases; or
- (iii) The stresses leading to cyclic fatigue increase.

Integrity Management Implications

- PG&E had a practice of raising the operating pressure to MAOP once every 5 years on several of its pipelines, including Line 132 and the other peninsula lines (Lines 101 and 109), as a strategy to continue classifying any manufacturing and construction defects on those lines as “stable,” meaning that they were not anticipated to grow in service.

Integrity Management Implications

- PG&E believed under certain circumstances where the operating pressure is raised above the maximum pressure experienced during the preceding [5] years, PHMSA regulations … require the operator to schedule a priority assessment capable of assessing seam integrity.
- PG&E believed in these circumstances, ASME B31.8S calls for a hydrostatic pressure test, which would take a line out of service for a period of at least a week.
- To avoid this and any potential customer curtailments that may result, PG&E operated, within the applicable 5-year period, some of its pipelines that would be difficult to take out of service at the maximum pressure experienced during the preceding 5-year period in order to meet peak demand and preserve the line's operational flexibility.
- So in 2003 and 2008 Line 132 was raised to 400 psig at the Milpitas Terminal

Integrity Management Implications

- the practice of "artificially raising the pressure in a pipe that has identified integrity seam issues seems to be a wrong-headed approach to safety." CPUC at NTSB hearing March 2011
- PHMSA officials were unaware of any other operators following such a practice.
- The principal challenge for deciding whether or not to consider manufacturing defects to be stable is associated with those gas pipelines that have never been subjected to a hydrostatic test to a minimum of 1.25 times MAOP…. *from PHMSA Report 2007 O5-12 R*

Integrity Management Implications

- *"an integrity management program without integrity," NTSB Chairwoman Deborah Hersman*

  NTSB Board Hearing Aug 29, 2011

Topics

- Impact of the San Bruno Explosion (Overview)
- Explosion Images
- Ruptured Segment – Determination of Root Cause
- IMP Risk Ranking
- **NTSB Results**
- Response Times,
- Record Keeping
- Legislative Implications

Official Probable Cause

and….

- NTSB determines that the probable cause of the accident was (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe.

Investigation Timeline (cont'd)

- **INGAA issued Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of PG&E San Bruno Incident May 5, 2011 (55)**
- **CPUC investigation issued final report June 8, 2011 (196)**
- **NTSB produced final report Sept 26 2011 (140)**

Preliminary Analysis of Publicly Available Evidence Supporting a Failure Cause of PG&E San Bruno Incident

INGA

Table of Contents

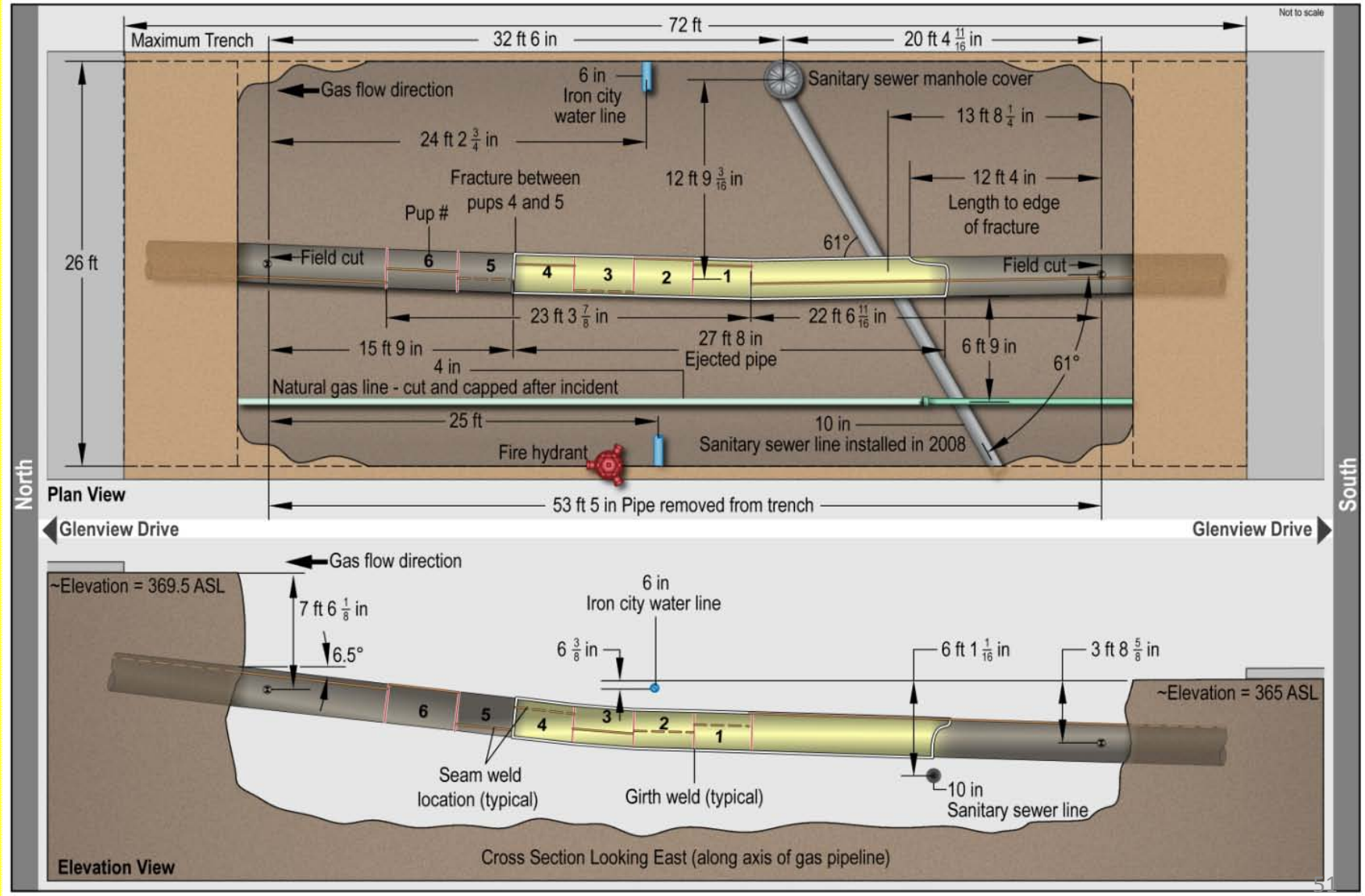
Executive Summary
Facts Pertaining to the Original Construction as Documented ir
Key Findings
INGAA Analysis of Publicly Available Information
Possible Cause of the Final Failure of the Longitudinal Weld
Suggestions to NTSB that may clarify the root cause
INGAA Analysis of the Root Cause of the San Bruno Pipeline Ac
INGAA Analysis of NTSB Metallurgical Group Factual Repor
Strength of the Remaining Material in Pup #1 Long Seam
Fatigue Behavior of the Longitudinal Seam of Pup #1
INGAA Analysis of External Force Activating Defect on Pup #
Conclusions Based on INGAA Analysis
Appendices
Appendix A. Background Information
Pipeline Pup Configuration
Fabrication Details
Appendix B. Vintage Standards and Processes to Eliminate No
Quality Controls and Safety Redundancy
Natural Gas Transmission Pipeline Manufacturing
Construction of the Transmission Pipeline
Integrity Management Regulations
Pipeline Operating Conditions
Appendix C. Public Media Reports
Raising of the Operating Pressure on Pipeline Segment
Mechanical Damage of the Pipe Segment
Fatigue of the longitudinal weld on Pup #1
In-Line Inspection of the Pipeline Segment

Appendix D. Results of the NTSB Laboratory Factual Reports (Exhibit 458194 and Exhibit 459591) 47
Steel Chemistry 48
Yield Strength of Steel 48
Rolling Direction of the Pups 49
Girth Welding 49
Pressure Tests 50
Appendix F. Definitions of Terms 53

Key Findings

1. Both the material and the fabrication welds of the section of pipeline that failed in San Bruno did not meet the engineering consensus standards applicable to natural gas transmission pipelines and the PG&E specifications in effect at the time of construction.
2. A hydrostatic pressure test of the pipeline probably would have detected the initial weld seam defect and low material strength of the fabricated pipe section. Fatigue analysis of the failed pipeline section suggests that an external force was necessary to cause further deterioration of the initial longitudinal weld seam flaw.
3. Assuming both that our analysis is correct and that the public record reflects all material facts, the external event that most likely caused increased stress on the longitudinal weld seam of Pup #1 was a 2008 sewer replacement project.

From NTSB Report



How did the Fracture Occur?

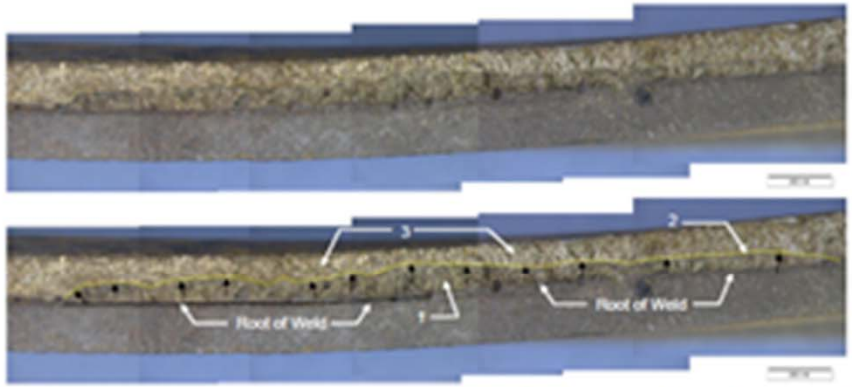


Figure 34: Optical micrographs of the fracture initiation site in pup 1. Top: Unlabelled micrograph, Bottom: Same micrograph with a crack arrest mark indicated by a yellow dotted line and the three fracture surface morphologies identified by scanning electron microscopy, 1 - ductile overstress (dimple rupture), 2 – progressive fracture, 3 –quasicleavage. The black arrows indicate the approximate direction of crack propagation. Note: The micrographs were taken after an inhibited acid solution was used to remove iron oxides.

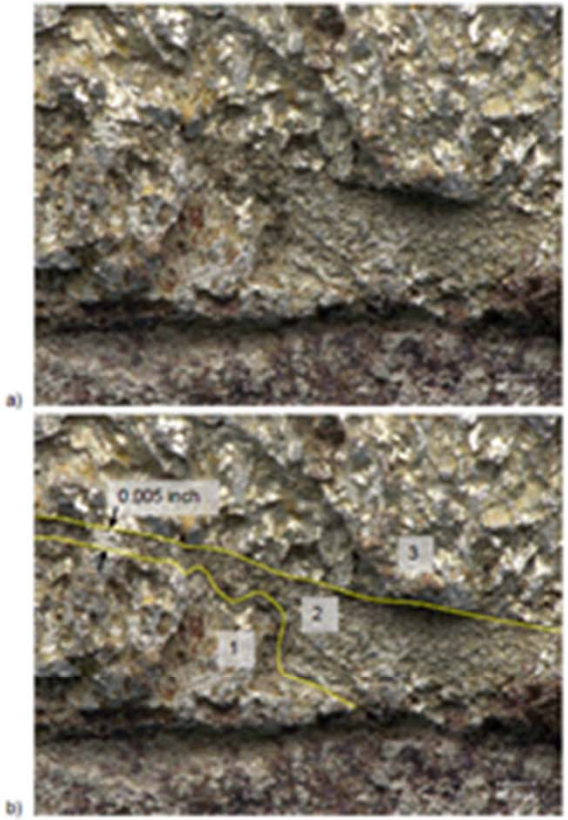
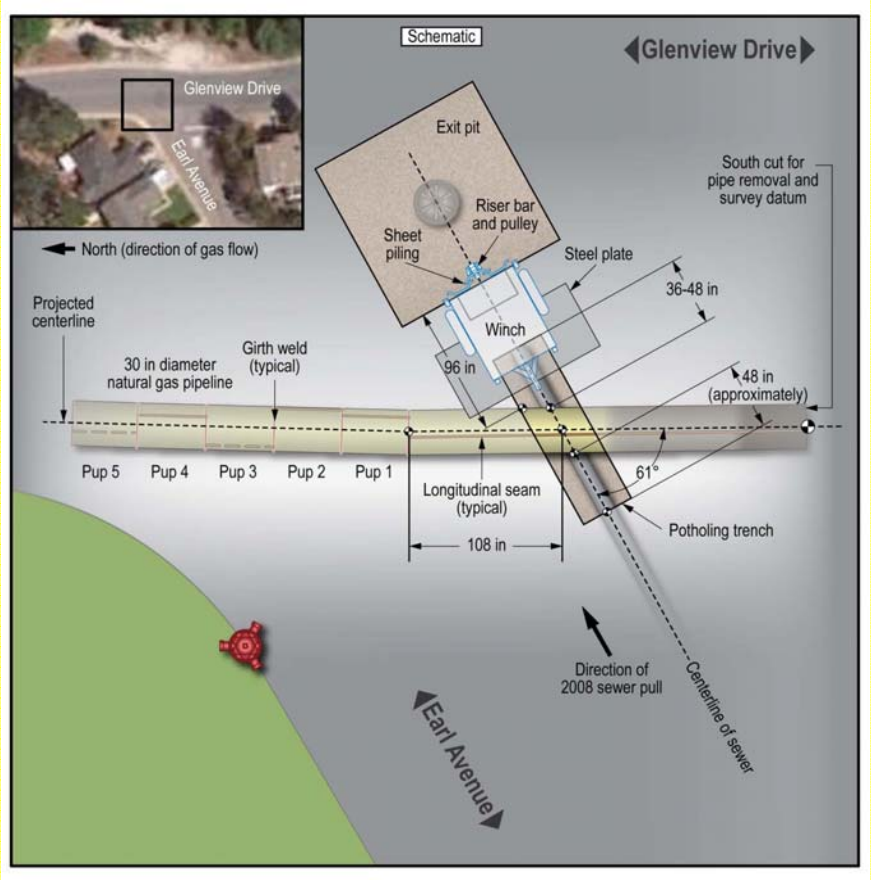


Figure 37: Photomicrograph of the north end of the fracture surface at the 22.7 inch mark. A flat fracture surface region at the crack arrest mark was observed between the yellow dashed lines in the bottom micrograph; a) micrograph without annotations; b) micrograph with annotations.

Figure 1. Source: NTSB Metallurgical Report 3A, exhibit 459184. The NTSB photos show the lack of penetration, the ductile Zone 1 and striated Zone 2.

Subsequent NTSB Final Report

- NTSB discounted the effect of the Sewer installation as a root cause of the failure
- Considered video of jacking operation
- Considered Studies on pipe bursting by Army Corp of Engineers 2001 and 2004 Paper at North American Trenchless Technology regarding Vibrations
- Found equivalent stress on pipe was raising internal hoop stress to approximately
  - 6 psi due to bursting head
  - 2.5 psi due to external soil pressure
  - .01 psi due to vibrations
- Considered **minimal** compared to the pressure variations within the pipe of 110 psi



Topics

- Impact of the San Bruno Explosion (Overview)
- MAOP Establishment
- Explosion Images
- Ruptured Segment – Determination of Root Cause
- IMP Risk Ranking
- NTSB Results
- Public Awareness
- **Response Times**
- Record Keeping
- Legislative Implications

Emergency Response Timeline (1)

- 6:11 pm call to 911
- Fire, gas station explosion, possible airline crash
- 6:12 pm Police arrive on scene
- 6:13 pm Fire Dept on scene (less than 300 yds away)
- 6:18 pm off duty PG&E employee notified PG&E dispatch of explosion
- 6:23 pm dispatch sent PG&E service tech from approximately 8 miles away
- 6:24 pm Fire Reported fire hydrants were dry (resulted from damaged water line)

Emergency Response Timeline (2)

- 6:27 pm PG&E Dispatch asks PG&E SCADA center if pressure drop observed
- 6:30 pm PG&E SCADA center realizes the there was a pressure drop on Line 132, a possible rupture and possible reported over pressurization at the Milpitas terminal to the South
- 6:30 pm Incident Commander of Fire Dept declares a multi casualty scene at Earl Ave, Claremont Drive and Glenwood Drive neighborhood
- 6:40 pm first off duty PG&E employee (supervisor) arrives at scene (was on his way home) Seconds later the PG&E Service Tech arrives on scene.

Emergency Response Timeline (3)

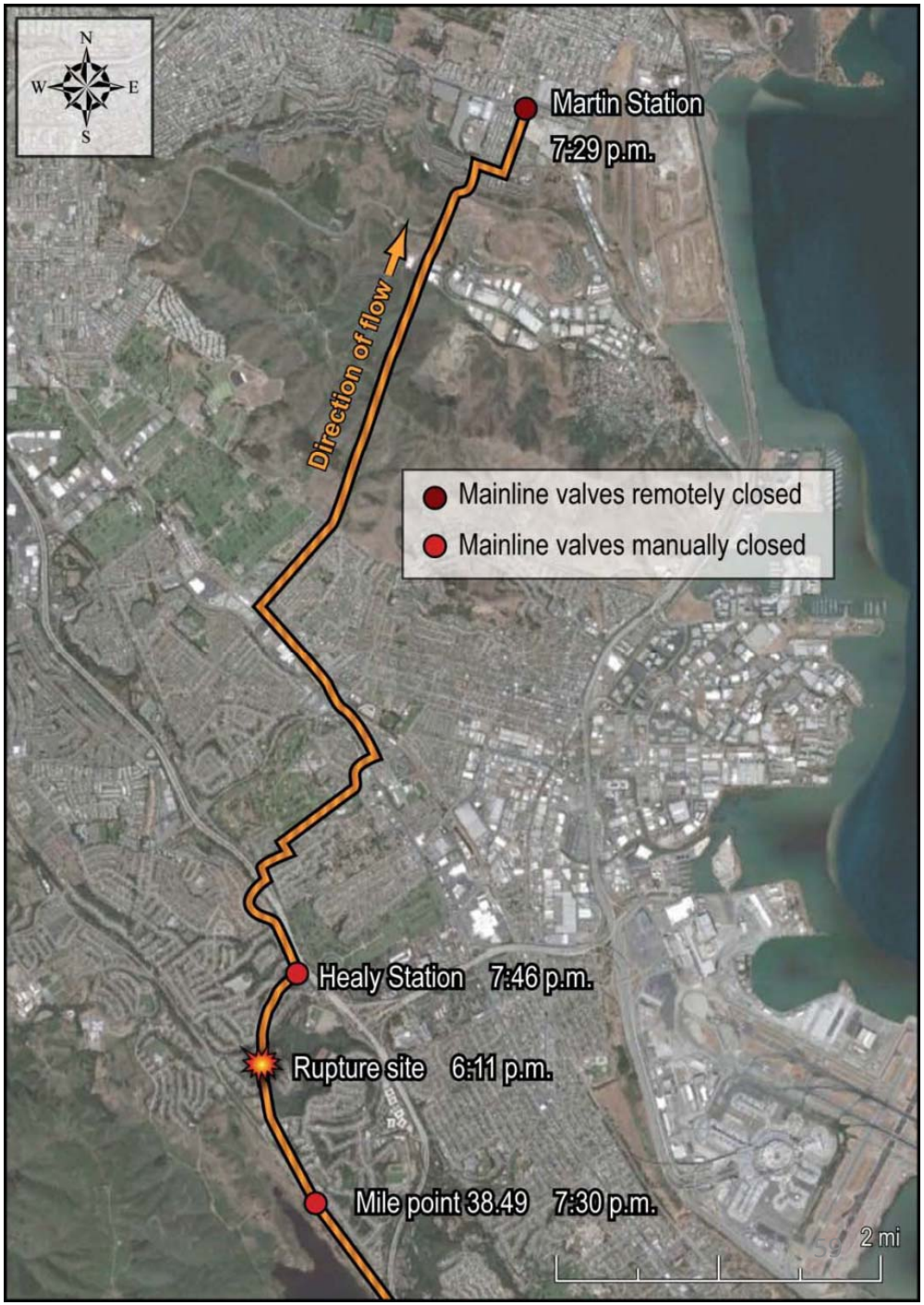
- 6:48 pm call by on scene PG&E to PG&E Dispatch requesting assistance from gas and electric crews
- 6:55 pm PGE Emergency Center was activated
- 7:06 pm PG&E mechanics left nearest yard to shut off southern valve
- 7:20 pm PG&E mechanics arrived at valve and begin to manually shutoff southern valve
- 7:30 pm PG&E mechanics arrived at valve and begin to manually shutoff southern valve

Emergency Response Timeline (4)

- 7:22 pm call by on scene PG&E to PG&E Dispatch confirming gas fire and Line 132 involved
- 7:27 pm PG&E on scene requested Scada Center to shutoff Remote Controlled Valves located at Martins Terminal (north)
- 7:29 pm Remote Controlled Valves were shutoff by Scada Center
- 7:42 pm fire diminished to a level that fire fighters could approach the rupture area
- 7:46 pm PG&E mechanics shutoff valves on northern side manually at Healy Station

Emergency Response

- 7:57 pm PG&E engineer confirmed location of rupture to Scada Center and that cross ties to Line 109 had been opened at the Martins Station to keep Line 100 active.
- 7:57 pm Red Cross set up shelter
- 11:32 pm more PG&E crews squeezing off distribution lines to limit gas fed house fires
- 4:24 am Sept 11, 2010 75% all house fires knocked down
- 8:00 pm Sept 11 Incident Command transferred to PD and FD monitoring hot spots



NTSB Overall Review of ER

1. PG&E took 95 minutes to stop the flow of gas and to isolate the rupture site—a response time that was *excessively long* and contributed to the extent and severity of property damage and increased the life-threatening risks to the residents and emergency responders.
2. The National Transportation Safety Board found that PG&E *lacks a detailed and comprehensive procedure for responding to large-scale emergencies* such as a transmission pipeline break, including a defined command structure that clearly assigns a single point of leadership and allocates specific duties to supervisory control and data acquisition staff and other involved employees.

NTSB Overall Review of ER

3. PG&E's *supervisory control and data acquisition system limitations caused delays in pinpointing the location* of the break.

4. The use of either automatic shutoff valves or remote control valves would have reduced the amount of time taken to stop the flow of gas.

NTSB Specific findings of ER

- PG&E's SCADA center communication protocols did not use Incident Command System, lack of centralized command structure
- Lack of assigned roles and responsibilities led to not allocating their time and attention in the most effective manner
- Unnecessary overlap and duplication of efforts was demonstrated
- PG&E explanation for not using Remote Control Valves or Automated Control Valves was contradictory to 192.

NTSB Specific findings of ER

- PG&E explanation for not using Remote Control Valves or Automated Control Valves was contradictory to 192.935(c) Integrity Management Requirements and was inconsistent with non industry sponsored studies
- 192.935(c), "[i]f an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV."

CPUC Independent Report

- CPUC Independent Report stated that sewer work conducted by City of San Bruno in 2008 could have triggered the threat from “stable” to “unstable”
- CPUC report emphasized the breakdown of communications within PG&E regarding field work and integrity management responsibilities in regards to potential of failure

NTSB San Bruno Incident Sept 2010 -28 Findings as it relates to Operator, State Regulator, Federal Regulator

- **Findings 1-23 have specific findings of PGE about**
  - **the Cause of the incident**
  - **Lack of contingency plan for associated work on nearby pipeline facility**
  - **No incident command system used for control center**
  - **Scada system contributed to, added to delays in response**
  - **Use of Automated and Remote Control Valves would have reduced impact**
  - **Excessively long response times experienced**
  - **Ineffective public awareness plan**
  - **Ineffective post accident for drug & alcohol testing**
  - **Deficient Integrity Management Program with Inadequate Record Keeping and treatment of unstable threats**

NTSB San Bruno Incident Sept 2010 -28 Findings as it relates to Operator, State Regulator, Federal Regulator

- **Findings 24-28 have 5 specific findings about**
  - **PHMSA and State Regulator regarding:**
    - **Ineffective IMP Inspection Protocols used during Inspection Process**
    - **Not able to evaluate IMP Program without establishing meaningful metrics**
    - **Improvement required of PHMSA regarding monitoring oversight of State Inspection Program**
    - **State Regulator had weak enforcement policy**

28 NTSB Findings

1. The following were not factors in this accident: seismic activity, corrosion, direct third-party damage, or drug use by the workers at the Milpitas Terminal.

2. The accident pipe comprising the pups did not conform to PG&E or other known specifications for pipe and was fabricated at an undetermined facility to no known specification.

3. The accident pipe would not have met generally accepted industry quality control and welding standards in 1956, indicating that those standards were overlooked or ignored.

4. PG&E's inadequate quality control during the 1956 relocation project led to the installation and commissioning of a defective pipe that remained undetected until the accident, 54 years later.

5. The fracture of Line 132 Segment 180 originated in the partially welded longitudinal seam of pup 1, which was progressively weakened due to ductile crack growth and fatigue crack growth.

28 NTSB Findings

6. The combination of the size and shape of the weld defect significantly reduced the strength of the pup 1 longitudinal seam, making it susceptible to unstable crack growth under internal gas pressure.

7. The 2008 sewer line installation did not damage the defective pipe that later ruptured.

8. The internal line pressure preceding the rupture did not exceed the PG&E maximum allowable operating pressure for Line 132 and would not have posed a safety hazard for a properly constructed pipe.

9. Had a properly prepared contingency plan for the Milpitas Terminal electrical work been in place and been executed, the loss of pressure control could have been anticipated and planned for, thereby minimizing or avoiding the pressure deviations.

10. PG&E lacked detailed and comprehensive procedures for responding to a large-scale emergency such as a transmission line break, including a defined command structure that clearly assigns a single point of leadership and allocates specific duties to supervisory control and data acquisition staff and other involved employees.

28 NTSB Findings

11. PG&E's supervisory control and data acquisition system limitations contributed to the delay in recognizing that there had been a transmission line break and quickly pinpointing its location.

12. The 95 minutes that PG&E took to stop the flow of gas by isolating the rupture site was excessive.

13. Use of automatic shutoff valves or remote control valves along the entire length of Line 132 would have significantly reduced the amount of time taken to stop the flow of gas and to isolate the rupture.

14. Considering the challenges of the prolonged fire fueled by natural gas, the emergency response was well coordinated and effectively managed by local responders.

15. The 6-hour delay before ordering drug and alcohol testing, the commencement of alcohol testing at the Milpitas Terminal 1 hour after it was no longer permitted, the failure to properly record an explanation for the delay, and the failure to conduct drug or alcohol testing on the supervisory control and data acquisition center staff all demonstrate that the PG&E postaccident toxicological program was ineffective.

28 NTSB Findings

16. If the grandfathering of older pipelines had not been permitted since 1961 by the California Public Utilities Commission and since 1970 by the U.S. Department of Transportation, Line 132 would have undergone a hydrostatic pressure test that would likely have exposed the defective pipe that led to this accident.

17. There is no safety justification for the grandfather clause exempting pre-1970 pipelines from the requirement for post construction hydrostatic pressure testing.

18. The premise in Title 49 Code of Federal Regulations Part 192 of the Federal pipeline safety regulations that manufacturing and construction-related defects can be considered stable even when a gas pipeline has not been subjected to a pressure test of at least 1.25 times the maximum allowable operating pressure is not supported by scientific studies.

19. The PG&E gas transmission integrity management program was deficient and ineffective.

20. PG&E's public awareness program self-evaluation was ineffective at identifying and correcting deficiencies.

28 NTSB Findings

21. The deficiencies identified during this investigation are indicative of an organizational accident.

22. The multiple and recurring deficiencies in PG&E operational practices indicate a systemic problem.

23. Because in-line inspection technology is not available for use in all currently operating gas transmission pipeline systems, operators do not have the benefit of a uniquely effective assessment tool to identify and assess the threat from critical defects in their pipelines.

24. The Pipeline and Hazardous Materials Safety Administration integrity management inspection protocols are inadequate.

25. Because PG&E, as the operator of its pipeline system, and the California Public Utilities Commission, as the pipeline safety

regulator within the state of California, have not incorporated the use of effective and meaningful metrics as part of their performance -based pipeline safety management programs, neither PG&E nor the California Public Utilities Commission is able to effectively evaluate or assess the integrity of PG&E's pipeline system..

28 NTSB Findings

26. Because the Pipeline and Hazardous Materials Safety Administration has not incorporated the use of effective and meaningful metrics as part of its guidance for effective performance-based pipeline safety management programs, its oversight of state public utility commissions regulating gas transmission and hazardous liquid pipelines needs improvement.

27. The ineffective enforcement posture of the California Public Utilities Commission permitted PG&E's organizational failures to continue over many years.

28. The Pipeline and Hazardous Materials Safety Administration's enforcement program and its monitoring of state oversight programs have been weak and have resulted in lack of effective Federal oversight and state oversight exercised by the California Public Utilities Commission.

Topics

- Impact of the San Bruno Explosion (Overview)
- Explosion Images
- Ruptured Segment – Determination of Root Cause
- IMP Risk Ranking
- NTSB Results
- **Record Keeping**
- Legislative Implications

Record Keeping

- Integrity Management Concepts depend on Risk Management Concepts which are only as good as the data and records that are input
- Urgent Recommendation issued by NTSB to PHMSA January 3 2011
- PHMSA Advisory Bulletin 11-01 issued Jan 10, 2011
- PG&E *"has not been able to produce documentation on the origins of the pipe, the installation of the pipe, or the early inspection of the pipe,"* NTSB Chair D Hersman (1/27/2011)

Record Keeping

- Operators must review and scrutinize pipeline infrastructure documents and records, including but not limited to, all as-built drawings, alignment sheets, specifications, and all design, construction, inspection, testing, material manufacturer, operational maintenance data, and other related records, to ensure company records accurately reflect the pipeline's physical and operational characteristics. **These records should be traceable, verifiable, and complete to meet §§192.619 and 195.302.** Incomplete or partial records are not an adequate basis for establishing MAOP or MOP using this method. If such a document and records search, review, and verification cannot be satisfactorily completed, the operator may need to conduct other activities such as in-situ examination, pressure testing, and nondestructive testing or otherwise verify the characteristics of the pipeline when identifying and assessing threats or risks.

Topics

- Impact of the San Bruno Explosion (Overview)
- Explosion Images
- Ruptured Segment – Determination of Root Cause
- IMP Risk Ranking
- NTSB Results
- Public Awareness
- Response Times
- Record Keeping
- **Legislative Implications**

Federal Legislation

- New Legislation signed January 03 2012 by President Obama
- ‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.
- Replaces the 2006 Pipeline Safety Legislation signed by President Bush on Dec 29 2006 "**P**ipeline **I**nspection, **P**rotection, **E**nforcement and **S**afety Act (PIPES Act) of 2006“
- 32 Sections added or amended *Title 49 USC*

2012 Federal Legislation

Areas of Improvement

- *Enforcement*
- *New Regulations and Standards*
- *Expansions of Federal Oversight*
- *Additional New Requirements*
- *Study Requirements*

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 1. Short title; amendment of title 49, United States Code; definitions; table of contents.
- **Sec. 2. Civil penalties.**
- **Sec. 3. Pipeline damage prevention.**
- **Sec. 4. Automatic and remote-controlled shut-off valves.**

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 2. Civil penalties.** 2X

60122

- Increase fines from $100,000 per violation per day to $200,000 per violation per day. Maximum increased from $1,000,000 to $2,000,000 per series of violations
- Cap not apply to Enforcement Actions which can be greater $ amounts

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 3. Pipeline damage prevention.**

§6106

- In order to qualify for a grant under section 6106, a State one-call notification program may not exempt municipalities, State agencies, or their contractors from the one-call notification system requirements of the program.
- Becomes effective Jan 03 2014

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 3. Pipeline damage prevention.**

§60134 Report to Congress by Jan 2014

- (A) an analysis of the frequency and severity of different types of excavation damage incidents;
- (B) an analysis of exemptions to the one-call notification system requirements in each State;
- (C) a comparison of exemptions to the one-call notification system requirements in each State to the types of excavation damage incidents in that State; and
- (D) an analysis of the potential safety benefits and adverse consequences of eliminating all exemptions for mechanized excavation from State one-call notification systems.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 4. Automatic and remote-controlled shut-off valves.**

NEW

- **60102 within 2 years**
- Applies to New Transmission Pipelines only
- the Secretary, if appropriate, shall require by regulation the use of automatic or remote controlled shut-off valves, or equivalent technology, *where economically, technically, and operationally feasible* on transmission pipeline facilities constructed or entirely replaced after the date on which the Secretary issues the final rule containing such requirement.

"Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011".

- **Sec. 4. Automatic and remote-controlled shut-off valves.**

NEW

- **60102 within 1 year**
- Report to Congress regarding releases on gas transmission pipelines and haz liquid pipelines <u>in high consequence areas only</u>
- In conducting the study, the Comptroller General shall consider the swiftness of leak detection and pipeline shutdown capabilities, the location of the nearest response personnel, and the costs, risks, and benefits of installing automatic and remote-controlled shut-off valves.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 5. Integrity management.**
- Sec. 6. Public education and awareness.
- Sec. 7. Cast iron gas pipelines.
- Sec. 8. Leak detection.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 5. Integrity management.**

§601 DOT to Evaluate by July 2013, Report to Congress by Jan 2014

- (1) whether integrity management system requirements, or elements thereof, should be expanded beyond high-consequence areas; and
- (2) with respect to gas transmission pipeline facilities, whether applying integrity management program requirements, or elements thereof, to additional areas would mitigate the need for class location requirements.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 5. Integrity management.**

6 Factors to consider:

1. **The continuing priority to enhance protections for public safety.**
2. **The continuing importance of reducing risk in high consequence areas.**
3. **The incremental costs of applying integrity management standards to pipelines outside of high-consequence areas where operators are already conducting assessments beyond what is required under chapter 601 of title 49, United States Code.**

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 5. Integrity management.**

6 Factors to consider:

4. **The need to undertake integrity management assessments and repairs in a manner that is achievable and sustainable, and that does not disrupt pipeline service.**
5. **The options for phasing in the extension of integrity management requirements beyond high-consequence areas, including the most effective and efficient options for decreasing risks to an increasing number of people living or working in proximity to pipeline facilities.**
6. **The appropriateness of applying repair criteria, such as pressure reductions and special requirements for scheduling remediation, to areas that are not high-consequence areas.**

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 5. Integrity management.
- **Sec. 6. Public education and awareness.**
- Sec. 7. Cast iron gas pipelines.
- Sec. 8. Leak detection.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 6. Public education and awareness.**

§60132 and 60138

- Include HCA’s on National Piping Mapping System (Transmission only)
- Promote National Piping Mapping System to local Emergency First Responders (increase awareness)
- Provide specific system information to Emergency First Responders about facilities (distribution and transmission) in their communities
- Pipeline Operators to provide a copy to DOT of Emergency Response Plan

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 5. Integrity management.
- Sec. 6. Public education and awareness.
- **Sec. 7. Cast iron gas pipelines.**
- Sec. 8. Leak detection.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 7. Cast iron gas pipelines.**

- **§60108**
- Follow-up survey of cast iron replacement every 2 years
- the Secretary shall conduct a follow-up survey to measure the progress that owners and operators of pipeline facilities have made in adopting and implementing their plans for the safe management and replacement of cast iron gas pipelines.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 5. Integrity management.
- Sec. 6. Public education and awareness.
- Sec. 7. Cast iron gas pipelines.
- **Sec. 8. Leak detection.**

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 8. Leak detection.**

- Applies only to hazardous liquid lines. DOT to complete
- (A) an analysis of the technical limitations of current leak detection systems, including the ability of the systems to detect ruptures and small leaks that are ongoing or intermittent, and what can be done to foster development of better technologies; and
- (B) an analysis of the practicability of establishing technically, operationally, and economically feasible standards for the capability of such systems to detect leaks, and the safety benefits and adverse consequences of requiring operators to use leak detection systems.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 9. Accident and incident notification.**
- Sec. 10. Transportation-related onshore facility response plan compliance.
- Sec. 11. Pipeline infrastructure data collection.
- Sec. 12. Transportation-related oil flow lines.
- Sec. 13. Cost recovery for design reviews.
- Sec. 14. Biofuel pipelines

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 9. Accident and incident notification.**

- By July 2013 Update CFR 191.5 and 195.52 to include 1 hour notifications to DOT during an incident or accident
- Operators to revise procedures to provide thorough and coordinated notification to all relevant State and local emergency response officials, including 911 emergency call centers, for the jurisdictions in which those pipeline facilities are located
- Estimate product released, fatalities, injuries within 48 hours to NRC

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 9. Accident and incident notification.
- Sec. 10. Transportation-related onshore facility response plan compliance.
- Sec. 11. Pipeline infrastructure data collection.
- Sec. 12. Transportation-related oil flow lines.
- Sec. 13. Cost recovery for design reviews.
- Sec. 14. Biofuel pipelines

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 15. Carbon dioxide pipelines.
- Sec. 16. Study of transportation of diluted bitumen.
- Sec. 17. Study of nonpetroleum hazardous liquids transported by pipeline.
- Sec. 18. Clarifications.
- Sec. 19. Maintenance of effort.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 20. Administrative enforcement process.
- **Sec. 21. Gas and hazardous liquid gathering lines.**
- **Sec. 22. Excess flow valves.**
- **Sec. 23. Maximum allowable operating pressure.**
- Sec. 24. Limitation on incorporation of documents by reference.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 21. Gas and hazardous liquid gathering lines.**

- DOT to Review any gaps concerning gathering lines:
- (A) the sufficiency of existing Federal and State laws and regulations to ensure the safety of gas and hazardous liquid gathering lines;
- (B) the economic impacts, technical practicability, and challenges of applying existing Federal regulations to gathering lines that are not currently subject to Federal regulation when compared to the public safety benefits; and
- (C) subject to a risk-based assessment, the need to modify or revoke existing exemptions from Federal regulation for gas and hazardous liquid gathering lines.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 23. Maximum allowable operating pressure.**

- **§60139**
- By July 2012
- For all Class 3 and Class 4 locations
- For Class 1 and Class 2 locations within HCAs :
- Verify Records to ensure that the records accurately reflect the physical and operational characteristics of the pipeline and confirm the established maximum allowable operating pressure of the pipelines.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 23. Maximum allowable operating pressure.**

- **§60139**
- By July 2012
- For all Class 3 and Class 4 locations
- For Class 1 and Class 2 locations within HCAs :
- Verify Records to ensure that the records accurately reflect the physical and operational characteristics of the pipeline and confirm the established maximum allowable operating pressure of the pipelines.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 23. Maximum allowable operating pressure.**

- **§60139**
- By July 2013:
- Operators must report to DOT any segments that have insufficient data to verify MAOP
- Report to DOT any discovered exceedence of MAOP based on record verification
- Expeditiously Reconfirm the MAOP of those pipelines in which insufficient data was found
- Determine actions that are appropriate in the interim.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 23. Maximum allowable operating pressure.**

- **§60139**
- By July 2013:
- DOT will issue regulations requiring pressure testing (strength testing) for those pipelines previously untested (grandfathered) if the SMYS is greater than 30% based on operating pressure.
- Alternative methods may be considered such as inline inspections
- Coordinate with FERC if disruptions are anticipated

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- Sec. 25. Pipeline safety training for State and local government personnel.
- Sec. 26. Report on minority-owned, woman-owned, and disadvantaged businesses.
- Sec. 27. Report on pipeline projects.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 28. Cover over buried pipelines.**
- Sec. 29. Seismicity.
- Sec. 30. Tribal consultation for pipeline projects.
- Sec. 31. Pipeline inspection and enforcement needs.
- Sec. 32. Authorization of appropriations.

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.

- **Sec. 28. Cover over buried pipelines.**

- Applies only to hazardous liquid lines
- For water body crossings greater than or equal to 100 ft
- Provide a study to Congress
- For those that are found defecient, determine the sufficiency of current requirements for the depth of cover over buried pipelines

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.
SUMMARY

- Reauthorizes federal pipeline safety programs of the Pipeline and Hazardous Materials Safety Administration (PHMSA) through FY 2015
- Provides regulatory certainty necessary for pipeline owners and operators to plan infrastructure investments and create jobs
- Improves pipeline transportation -- the safest and most cost-effective means to transport natural gas and hazardous liquid products -- by strengthening enforcement of current laws and filling gaps in existing law where necessary

‘‘Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011’’.
SUMMARY

- Ensures a balanced regulatory approach to improving safety that applies cost benefit principles
- Addresses National Transportation Safety Board recommendations resulting from recent pipeline incidents
- Protects and preserves Congressional authority by ensuring certain key rulemakings are not finalized until Congress has an opportunity to act
- Supported by both pipeline industry and safety advocates