UNITED STATES OF AMERICA

NATIONAL TRANSPORTATION SAFETY BOARD

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In the matter of: *

PUBLIC HEARING ON NATURAL GAS PIPELINE EXPLOSION AND FIRE SAN BRUNO, CALIFORNIA SEPTEMBER 9, 2010 * Docket No. DCA-10-MP-008

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Board Room and Conference Center
National Transportation Safety Board
429 L'Enfant Plaza East, S.W.
Washington, D.C. 20694

Tuesday,
March 1, 2011

The above-entitled matter came on for hearing, pursuant to Notice, at 9:00 a.m.

BEFORE: BOARD OF INQUIRY
National Transportation Safety Board (NTSB)

APPEARANCES:

NTSB Board of Inquiry:

DEBORAH A.P. HERSMAN, Chairman
CHRISTOPHER A. HART, Vice Chairman
MARK R. ROSEKIND, Ph.D., Member
ROBERT L. SUMWALT, Member
EARL F. WEENER, Ph.D., Member

NTSB Technical Panel:

RAVINDRA CHHATRE, Investigator-in-Charge
MIKE BROWN, Transportation Safety Specialist
MIKE BUDINSKI, Chief, Material Labs
KARL GUNTHER, Chairman, Operations Group
MATT NICHOLSON, P.E., Pipeline Investigator
DANA SANZO, Survival Factors Group Chairman
CARL SCHULTHEISZ, Ph.D., Materials Investigator
BOB TRAINOR, P.E., Chief, Pipeline and Hazardous Materials Division
FRANK ZAKAR, Materials Investigator
LORENDA WARD, Hearing Officer
MARK JONES, Audio/Visual

Interested Parties:

PAUL CLANON, Executive Director, California Public Utilities Commission (CPUC)
CONNIE JACKSON, City Manager, City of San Bruno, California
KIRK JOHNSON, Vice President, Gas Engineering Operations, Pacific Gas and Electric Company (PG&E)
DEBBIE MAZZANTI, Business Representative, International Brotherhood of Electrical Workers (IBEW), Local 1245
JEFF WIESE, Associate Administrator for Public Safety, U.S. Department of Transportation, Pipeline and Hazardous Materials Administration (PHMSA)

Witness Panel 1:

BRIAN DAUBIN, Manager, Engineering Support Services, PG&E
MARK KAZIMIRSKY, Supervising Engineer, SCADA and Controls Group, PG&E
CHIH-HUNG LEE, Senior Gas Consulting Gas Engineer, Engineering and Operations, PG&E
SARA BURKE PERALTA, Manager, Integrity Management Program, PG&E

APPEARANCES (Cont.):

Witness Panel 1 (Cont.):

EDWARD SALAS, Senior Vice President, Engineering and Operations, PG&E
KEITH SLIBSAGER, Manager, Gas System Operations, PG&E

Witness Panel 2:

FRANK DAUBY, Supervising Engineer, Gas Transmission and Distribution Engineering, PG&E
BOB FASSETT, Director, Integrity Management and Technical Support, PG&E
EDWARD SALAS, Senior Vice President, Engineering and Operations, PG&E

Also Present:

PETER KNUDSON, Press Contact, NTSB
ELIAS KONTANIS, Office of Transportation Disaster Assistance, NTSB
DENISE WHITFIELD, Administration Support, NTSB
NANCY MASON, Administration Support, NTSB
ANTION DOWNS, Audio/Visuals Operator, NTSB

I N D E X

I N D E X (Cont.)

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P R O C E E D I N G S

(9:00 a.m.)

CHAIRMAN HERSMAN: Good morning. I am Debbie Hersman, and it is my privilege to serve as the Chairman of the National Transportation Safety Board. Along with my fellow Board members, we are serving as the Board of Inquiry for this hearing. I am joined by Vice Chairman Chris Hart, Member Robert Sumwalt, Member Mark Rosekind and Member Earl Weener.

I would like to recognize, in particular, Vice Chairman Hart for serving as the spokesperson for NTSB during our on-scene portion of our investigation in San Bruno and also for representing the Agency so well at congressional hearings to discuss our investigative activities last fall before both the House and Senate.

Today we begin a 3-day hearing on the accident in San Bruno, California, involving a Pacific Gas and Electric Company natural gas transmission line. On September 9, 2010, a little after 6:00 p.m., as families were returning home from work and sitting down at the dinner table, a 30-inch natural gas pipeline ruptured. The explosion created a 76-foot-long crater and the released natural gas ignited. The 28-foot segment of the pipeline was shattered out of the ground and blasted about 100 feet away. Over an hour passed before the valves were shut and the flow of gas stopped.

The toll was significant. Eight lives were lost, numerous others were injured, homes were destroyed and a neighborhood was evacuated. The footage on TV was dramatic. How did this happen? And many of us were wondering, could it happen again?

On behalf of my fellow Board members and the NTSB staff, I offer our deepest condolences to the families and friends of those who lost loved ones and our wishes for continued recovery for those who experienced injuries. Nothing can replace the loss of a loved one or repair the trauma of a life-changing injury. But we do have the opportunity and the obligation to take every step possible to ensure that the lessons of this tragedy are well-learned and that the circumstances are not repeated. As we continue with our investigation, we are mindful that on September 9th, the community of San Bruno was changed forever.

I'd like to extend the Board's appreciation to the first responders in the San Bruno community who responded in the moments and early hours after the explosion. In the days following the accident, Vice Chairman Hart and our team met with many local, state and federal officials. In the months since then, community leaders representing San Bruno have supported the work of the NTSB to conduct an independent and thorough accident investigation.

Like many of our prominent accident investigations, this accident has the interest of many members of Congress. Senators Boxer and Feinstein and Representative Speier have held local meetings, introduced pipeline safety legislation, and visited our laboratories to understand this tragedy, and they share our commitment to ensuring the safety of the public.

In particular, I'd like to recognize Representative Speier who is with us today in the audience. If you could stand up, just so everyone could acknowledge you. Thank you very much for being here and for your continued support of our investigation.

Approximately 2.5 million miles of pipeline exist in the United States today. They run throughout our neighborhoods and provide energy to homes and businesses. Because of the strong safety record of these pipelines and the fact that they're typically underground, most people don't even know that they exist. Therefore, it is all the more important that pipeline operators and those responsible for regulating them make sure the nation's pipeline system is as safe as possible.

Over the next 3 days, our hearing will serve as an exercise in accountability and transparency. It will give the public a window into the investigative process to ensure that the Safety Board is conducting a thorough and fair investigation; federal and state agencies are regulating the industry adequately; utility companies are operating safely; and products have been manufactured and perform safely.

The NTSB is currently investigating five pipeline accidents across the United States involving two hazardous liquid line ruptures and three gas accidents, in Florida, Texas, Michigan, Illinois and this accident in California. Four of these occurred in the last year. However, there have been nine other major accidents that have occurred in the past year involving fatalities that the NTSB has elected to delegate to other authorities due to our current investigative workload and staffing constraints. Two of these accidents were delegated to PHMSA and seven were delegated to state authorities, including the two recent accidents that occurred in Pennsylvania. Although PHMSA and the state officials are investigating these accidents, we continue to monitor them in support of our ongoing investigations for new or novel issues that may have a nationwide impact.

The Safety Board does not hold public hearings on every accident investigation. We simply do not have the resources to do so. However, we do hold several public hearings each year when there is a wide and sustained interest in the accident, and in this case, an opportunity for lessons to be learned by discussing the facts and circumstances of the accident in the public view.

We are still in the fact-finding stages of our investigation, but this hearing is a critical component of that work, allowing us to gather additional facts and further develop the record on how and why the pipeline ruptured.

Once the fact-finding stage is completed, the Safety Board will prepare an accident report. We will then hold another public meeting, called a Board meeting, to consider the evidence, review the analysis, determine the probable cause of the accident and issue recommendations.

The Safety Board does not always wait until our investigations are completed before issuing safety recommendations. Early in this investigation we identified safety concerns that we believed required urgent action, and so on January 3rd, 2011, the Board issued seven recommendations, six of which were classified as urgent. These recommendations were issued to PHMSA, the federal regulator; CPUC, the state regulator; and PG&E, the pipeline operator.

The urgent recommendations called on pipeline operators and regulators to ensure that records, surveys, and documents for all pipeline systems accurately reflect the infrastructure as built throughout the United States so that maximum safe operating pressures are accurately calculated and, in the absence of such records, to conduct hydrostatic testing to establish the maximum safe operating pressure of the pipeline in San Bruno, in PG&E.

All recipients of the urgent recommendations are working to address them, but I would like to specifically acknowledge PHMSA, who within a day of receiving our urgent recommendation, issued guidance informing the pipeline industry of the circumstances of the San Bruno accident and the consequences of the San Bruno rupture, as we had recommended, and that recommendation has already been closed out.

Now, for a few comments on how we will conduct the hearing.

Last week, on February 23rd, 2011, the NTSB conducted a prehearing conference attended by our Technical Panel and the Parties to this hearing. At this conference, we delineated the issues that we would be discussing at the hearing and developed a list of witnesses and exhibits. The witnesses were selected because of their ability to provide the best available information on the issues. Hard copies of the witness list are available in the atrium outside of the boardroom, and both the witness list and the exhibits are posted on the NTSB website and are available in the docket.

There are five broad issues that we scoped to cover at this hearing. They are Pacific Gas and Electric operations, Pacific Gas and Electric's integrity management program, public awareness, state and federal oversight, and industrywide technology.

At this point, I would like introduce the NTSB's Technical Panel. They will be assisting the Board of Inquiry and they possess operational and technical expertise in pipeline safety issues. They include our Hearing Officer, Ms. Lorenda Ward; Ms. Dana Sanzo, Survival Factors Group Chairman; Mr. Matt Nicholson, Pipeline Investigator; Mr. Bob Trainor, Chief of Pipeline and Hazardous Materials Division; Mr. Karl Gunther, the Operations Group Chairman; and seated in the second row, Mr. Mike Brown, Transportation Safety Specialist; Mr. Michael Budinski, Chief of the Materials Lab; Mr. Carl Schultheisz, Materials

Investigator; Mr. Frank Zakar, Materials Investigator; and also Mr. Mark Jones, who will be doing audio/visual for us.

Also assisting in our investigation are Mr. Peter Knudson, Mr. Elias Kontanis, Ms. Nancy Mason and Denise Whitfield, seated on the left, as well as Mr. Antion Downs, who is operating the audio/visuals.

And you will see our Investigator-in-Charge, Mr. Ravi Chhatre, sitting on the witness stand, as he will have a presentation shortly.

I will now introduce the Parties designated to participate in the public hearing. As prescribed in the Safety Board's Rules, we designate as Parties those persons, government agencies, companies and associations whose participation we deem necessary and in the public interest and whose special knowledge will contribute to the development of pertinent evidence.

As I call the name of the party, I would ask the designated spokesperson to state for the record his or her name, title, and affiliation, and we'll begin with PHMSA.

MR. WIESE: Good morning. My name is Jeff Wiese. I'm the associate administrator for pipeline safety at U.S. DOT's Pipeline and Hazardous Materials Safety Administration.

CHAIRMAN HERSMAN: Very good. Thank you. PG&E.

MR. JOHNSON: Good morning. I'm Kirk Johnson. I'm the vice President of gas engineering operations for Pacific Gas and Electric Company.

CHAIRMAN HERSMAN: Thank you. CPUC.

MR. CLANON: Chair, I'm Paul Clanon, the executive director at the Public Utilities Commission in California.

CHAIRMAN HERSMAN: Thank you. City of San Bruno.

MS. JACKSON: Thank you, Madam Chair. I'm Connie Jackson, City Manager, City of San Bruno.

CHAIRMAN HERSMAN: And the International Brotherhood of Electrical Workers, Local 1245.

MS. MAZZANTI: Good morning. I'm Debbie Mazzanti, IBEW Local 1245, business rep, out of Vacaville, California.

CHAIRMAN HERSMAN: Thank you very much.

On behalf of the entire Safety Board, I'd like to thank the Parties and the many other municipal, state and federal officials for their cooperation and support of our investigative activities. The voluminous docket of thousands of pages that was released this morning is a testament to the depth of the teamwork and cooperation that we have received from all who are participating in the investigation.

We will proceed over the next 3 days as follows:

We will begin this morning with a presentation from the Investigator-in-Charge, Mr. Chhatre, who will summarize the facts about the accident and the investigative activities to date.

We will then proceed, in sequence, one panel at a time for each of the hearing issues that we identified. In each panel, the witnesses will be called, introduced by name, their qualifications will be noted, and they will testify under oath. They will be questioned first by our Technical Panel, then by the designated spokesperson from each party, and finally, by the Board of Inquiry. Due to time constraints, and as a courtesy to other participants, we will limit the questioning periods for the Parties and each of the Board members to 5 minutes.

After the first round of questioning is completed, I will permit a second round of questioning only if there is information that needs to be clarified or if new matters have been raised that require further explanation. If a party would like a second round of questions, the designated spokesperson should make that request, state the reason for the request, and I would expect any second round of questioning to be very brief and not repetitive.

Once a witness has completed his or her testimony, they could be recalled for questioning later in the hearing. So please check in with our Hearing Officer, Ms. Ward, if you need to be excused after you testify.

This hearing is not adversarial. There will be no adverse parties or interests and no formal pleadings or cross-examinations. The Safety Board will not determine liability and questions directed to issues of liability will not be permitted. As Chairman of the Board of Inquiry, I will make rulings on the admissibility of all evidence and my rulings will be final.

The transcript of the hearing, exhibits entered into the record, the presentations made by the witnesses, along with any other records of the investigation, will become part of our public docket. Those docket materials are available on our website at www.ntsb.gov.

Mr. Chhatre, are you ready to summarize the work of the investigative team thus far?

MR. CHHATRE: Madam Chairman, I am.

On September 9, 2010, at approximately 6:11 p.m., Pacific Daylight Time, a natural gas transmission pipeline owned and operated by Pacific Gas and Electric Company, or PG&E, ruptured in a residential area in San Bruno, California.

PG&E provides natural gas and electric service to approximately 15 million people throughout a 70,000 square mile service area in northern and central California. Their gas facilities include 42,141 miles of natural gas distribution pipelines and 6,438 miles of transportation pipelines.

The rupture occurred at the intersection of Earl Avenue and Glenview Drive in the City of San Bruno. The rupture is indicated by the white oval. The rupture caused an estimated 47.6 million standard cubic feet of natural gas to be released. The released natural gas ignited, resulting in a fire that destroyed 38 homes shown here in red and damaged 70 shown in yellow. Eight people were killed, numerous individuals were injured, and many more were evacuated from the area.

A video of the event was obtained and has been shortened to give you a sense of the magnitude of the fire. It will play for approximately 1-1/2 minutes. This video is footage of the fire caused by the pipeline rupture. It is looking east down Earl Avenue towards the rupture location. This video transitions into a zoomed-in view of the fire, followed by two aerial post-rupture photographs that show the crater caused by the rupture and the surrounding damage. This video contains audio of the rupture.

(Video played.)

This is an aerial view of the rupture and the crater.

The section of transmission pipeline that ruptured was part of PG&E's Line 132. Line 132 is approximately 47 miles long and originates at the Milpitas Terminal, located at the bottom right of the slide. The gas flow is from south to north as shown in the slide. Line 132 terminates at the Martin Station, located near the top left corner of the slide.

PG&E's gas transmission pipelines are controlled by a supervisory control and data acquisition control center, or SCADA, control center located northeast of San Bruno in San Francisco.

On September 9th prior to the accident, PG&E personnel were working on an electrical distribution panel as part of a replacement project for the uninterrupted power supply unit, or UPS, at the Milpitas Terminal. During the course of the work at Milpitas Terminal, the power supply modules for the pressure transmitters and the other control devices malfunctioned. The electronic signal to the pressure-regulating valves, including one for Line 132, was lost causing the valves to move immediately from a partially opened position to a fully opened position.

A pneumatically actuated valve designed to protect Line 132 from overpressurization was automatically activated to control downstream line pressure at a predesignated value. The Line 132 pressure at Martin station showed a steady increase from 357 pounds per square inch, or psi, to 386 psi over a 46-minute period before the line ruptured at 6:11 p.m.

The control center in San Francisco registered a pressure drop at Martin Station from 386 psi to 135 psi within 5 minutes of the rupture, generating a low pressure alarm on Line 132. Within 10 minutes after the pipeline rupture, two off-duty PG&E employees reported the fire in San Bruno to the PG&E dispatch center in Concord, California.

The dispatch center dispatched an on-duty employee to investigate the reported explosion approximately 12 minutes after the pipeline rupture; however, he was not qualified to operate mainline valves. PG&E dispatched a crew that was capable of isolating the pipeline about 30 minutes after the rupture. PG&E crews manually closed the mainline valves upstream at Mile Point 38.49 and downstream at Mile Point 40.05, located less than 2 miles from each other. From the transmission and regulation mechanic's field notes we know that the upstream valve was closed at 7:30 p.m. and the downstream valve was closed at 7:45 p.m. At about 7:42 p.m. flames at the rupture location had diminished to the point that the firefighters were able to get closer to the ruptured pipeline.

This is a picture of the crater caused by the rupture of the pipeline. The crater was approximately 72 feet long and 26 feet wide. A 28-foot long section of pipe was ejected and came to rest 100 feet south of the crater on Glenview Drive.

This is a photograph of the 28-foot ejected section of the ruptured pipeline. This section of pipe contained 4 of the 6 pups or short pipe spools found in Line 132 at the rupture location. Each pup was between 3.5 feet to 4 feet long, and the NTSB materials laboratory report has identified variations in the material properties between them. There was no evidence of external or internal corrosion or stress corrosion cracking on the examined sections. The NTSB materials laboratory examination determined that the rupture initiated along a seam weld in pup 1, as shown in the picture.

The upper photo in the slide is a cross-section of the pup 1 seam in the ruptured pipe near the point of origin. The appearance of the weld was consistent with fusion welding along the exterior pipe seam. On average, the weld penetrated 55% of the wall thickness along pup 1. By contrast the longitudinal joint seams at the north and south ends of the rupture were consistent with a typical double submerged arc weld, or DSAW, with a full wall penetration as shown below.

In a 1956 realignment project, PG&E replaced approximately 1,851 feet of Line 132 that had been originally constructed in 1948. The section of the pipeline from north of Claremont Drive and extending south to San Bruno Avenue was rerouted from the east side to the west side of Glenview Drive. The pipe was identified in the PG&E geographical information system, GIS, database as a nominal diameter 30 inches, seamless, Grade X-42 pipe. PG&E's specified maximum operating pressure, or MOP, for the ruptured pipe was 375 psi. According to PG&E, the maximum allowable operating pressure, or MAOP, for the line was 400 psi.

In the Chairman's opening statement, she identified the issues areas for the hearing. I will now discuss some of these areas.

First, we'll ask questions to get a better understanding of PG&E's operations. The ruptured segment of pipeline was isolated 1 hour 20 minutes after the rupture by off-duty PG&E employees. We will be exploring some factors that contribute to typical PG&E control center response times during emergencies. Included will be a discussion of PG&E's policy regarding the use of automatic shutoff valves and remote-controlled valves.

The PG&E Integrity Management Plan states, quote, "The Company shall consider the addition of automatic shutoff valves or remote control valves if they would be an efficient means of adding protection to a high consequence area", endquote. In 2006, a PG&E senior consulting gas engineer wrote a policy memo which concluded that automatic shutoff valves and remote control valves, as a preventive and mitigation measure in a high consequence area, has little or no effect on increasing human safety or protecting properties.

The PG&E risk management program was developed to identify potential risks and mitigation measures to ensure the integrity of the pipeline. The factors that define this process and how the program was implemented on Line 132 will be explored. Establishing an accurate maximum allowable operating pressure is critical to safe operations of a pipeline. The use of the GIS system and how maximum allowable pressure was established at 400 psi will be discussed.

PG&E's policies concerning operations, safety and rapid shutdown in high consequence areas also will be looked at.

The PG&E gas control center is located in San Francisco. Here, the operators monitor and control the entire PG&E transmission network using supervisory control and data acquisition, SCADA. The SCADA system collects data from field instrumentation and displays this information to the gas system operator. Using this data, the gas operator can make changes to line pressures and valve positions in order to maintain the pipeline within established operating parameters.

SCADA will generate alarms based on the operating conditions of the line that the operators must address. The recognition of an abnormal event through SCADA trends and alarms are critical for an early detection of rupture and response. Operators rely heavily on the data collected and displayed over SCADA to make critical decisions about line operations.

The SCADA software prevents the operator from entering a pressure set point that exceeds the maximum operating pressure, MOP, of the pipeline. The operator can remotely operate some station valves to respond to emergencies.

PG&E's Gas Transmission Integrity Management Program is set forth in Risk Management Plan 6, RMP-6, which is one of the chapters concerning PG&E's Risk Management Plan. Integrity management is designed to provide methodology and procedures to ensure the safe operation of the gas transmission pipeline. PG&E's Integrity Management Plan was first implemented in December of 2004.

The plan states PG&E will conduct an inventory of all the pipeline design attributes, operating conditions, and environmental threats, such as structure faults, to the structural integrity of its pipeline systems. PG&E uses a geographical information system as a database of pipe attributes such as type of seam, age, maximum allowable operating pressure, yield strength and determination of high consequence areas.

High consequence areas are defined using the potential impact radius method, which designates a high consequence area by whether a calculated radius circle contains 20 or more dwellings. If it does, the area is classified a high consequence area regardless of class designation. The two factors used to calculate the potential impact radius are pipe diameter and maximum allowable operating pressure.

Pipeline and Hazardous Materials Safety Administration regulations require pipeline operators to develop and implement public awareness programs. These programs must follow the guidance in the American Petroleum Institute's Recommended Practice 1162. RP 1162 establishes guidelines for pipeline operators to develop, manage and evaluate public awareness programs.

According to PG&E's public awareness program plan, the objective of the plan is to enhance public safety through increased public awareness and knowledge. During this hearing, we will discuss the challenges of effectively conducting these programs.

As an intrastate gas transmission pipeline, Line 132 was regulated by the California Public Utilities Commission, the CPUC. In 2005, the CPUC conducted an integrity management audit of PG&E in which PHMSA participated. CPUC conducted a second integrity management audit of PG&E in 2010. There were no notices of violations cited in the 2010 CPUC audit letter.

Pipelines constructed before 1970 were not required by regulation to be pressure tested. This "grandfather clause" 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.

Additionally, we will be addressing the effectiveness of operator compliance in performance-based integrity management regulations. We will focus on the requirements of self-assessment programs by the pipeline operators and the approaches and policies of state and federal regulators in exercise of their oversight responsibilities.

Inspection options that were available to PG&E for Line 132 were external corrosion direct assessment, ECDA; use of inline inspection, ILI; pressure testing or other technologies. Because of bends, valves and changes in diameter that were present in the pipeline, Line 132 was not easily amenable for inline inspection. PG&E opted for external corrosion direct assessment technology on Line 132.

We are going to explore current technologies for inspecting and assessing the structural integrity of pipeline systems. We intend to identify the capabilities and trade-offs associated with these technologies. We are also going to discuss new technologies that might be available to operators in the future.

The NTSB was notified of the accident about 8:00 p.m. on the night of the accident. A Go-Team consisting of eight NTSB staff members was launched early the next morning. I would like to acknowledge Vice Chairman Hart, who was the Board member on scene, and the NTSB investigators and staff who have supported the accident investigation and public hearing preparations.

Assisting Safety Board staff were parties to the investigation, and these are Pipeline and Hazardous Materials Safety Administration, PHMSA; California Public Utilities Commission, CPUC; Pacific Gas and Electric Company, PG&E; the City of San Bruno; International Brotherhood of Electrical Workers Local 1245; and The Engineers and Scientists of California Local 20.

There were numerous state, local and federal agencies that were not parties to the investigation but played an important role in assisting the NTSB team with the ongoing portion of the investigation. Without their invaluable help, the on-scene process would have been significantly hampered.

Madam Chairman, this concludes my opening statement.

CHAIRMAN HERSMAN: Thank you, Mr. Chhatre.

Ms. Ward, are you ready to call the witnesses?

HEARING OFFICER WARD: Yes, Madam Chairman. If I could have Mark Kazimirsky, Keith Slibsager, Chih-Hung Lee, Edward Salas, Sara Peralta and Brian Daubin, please come to the witness table, and you can remain standing once you get there.

Please stand. Raise your right hand.

(Witnesses sworn.)

HEARING OFFICER WARD: Thank you. Please be seated.

Mr. Kazimirsky, we'll start with you, if you could please state your full name, your title and a brief description of your duties and responsibilities?

MR. KAZIMIRSKY: My name is Mark Kazimirsky. I'm a supervising engineer for SCADA and Controls Group at PG&E, and I'm supervising the group that's responsible for all SCADA and control systems throughout gas transmission pipelines at PG&E.

HEARING OFFICER WARD: Thank you.

Mr. Slibsager.

MR. SLIBSAGER: Good morning. My name is Keith Slibsager. I'm the manager of gas control at Pacific Gas and Electric Company. I'm responsible for the day-to-day operations of the gas system. That includes the remote monitoring and controlling of the pipeline as well as the management of pipeline inventory to safely serve our customers. I have 27 years' experience in gas operations, and I hold a bachelor's of science degree from California State University Fresno.

HEARING OFFICER WARD: Mr. Lee.

MR. LEE: My name is Chih-Hung Lee. I am senior consulting engineer in the Integrity Management Group. I'm the lead engineer in reviewing a long-term integrity management plan and also responsible for earthquake preparedness program for PG&E. I have 25 years experience with PG&E. Thank you.

HEARING OFFICER WARD: Mr. Salas.

MR. SALAS: My name is Edward Salas. I'm senior vice president of engineering and operations. My responsibilities include gas transmission, gas distribution, electric transmission and electric distribution for the utility. I've been with PG&E since April of 2007.

HEARING OFFICER WARD: And Ms. Peralta.

MS. PERALTA: My name is Sara Burke Peralta. I'm the manager of the integrity management program at PG&E. My responsibilities include oversight for the risk management, integrity management and operator qualification programs at PG&E. Thank you.

HEARING OFFICER WARD: And finally, Mr. Daubin.

MR. DAUBIN: My name is Brian Daubin. I'm the manager of engineering support services, several groups that support the engineering group, including gas transmission mapping, design, drafting, the estimating groups as well as some clerical.

HEARING OFFICER WARD: Thank you. Madam Chairman, the witnesses have been sworn in and qualified, and they're ready for Mr. Nicholson to begin questioning them.

CHAIRMAN HERSMAN: Thank you. Mr. Nicholson, please begin.

MR. NICHOLSON: Thank you, Madam Chairman.

Mr. Kazimirsky, I think we'll start with you, if we could, and discuss a little bit about Milpitas and the SCADA network. My first question to you is for you to describe for us a little bit about the Milpitas Station, the purpose of the station, and how it functions overall.

MR. KAZIMIRSKY: Milpitas Terminal is a gas transmission facility that collects the gas from four incoming lines and sends it out to San Francisco Peninsula and South Bay through five outgoing lines. If we can refer to Exhibit 2-EA, slide 4, I believe?

MR. NICHOLSON: Yes. Can we bring up 2-EA, please, Mr. Jones?

CHAIRMAN HERSMAN: And if any of the microphones are on, on the Panel, if you could turn those off just so that the only one that's on is the speaker's mic, so we don't get any feedback, and if you could make sure that the mic is close to you. Thank you.

MR. KAZIMIRSKY: No, that's not the right slide we need. I believe it's slide 4. That's the one.

So this slide shows four incoming lines and five outgoing lines from Milpitas Terminal. Each incoming line as well as outgoing lines or the outgoing header are provided with two valves. One valve is called a regulator valve, and that's a primary means of pressure and flow control. Each valve has an electric actuator. They are failed as is valves in case of a loss of electric power. They would fail open on a loss of a control signal. As the redundant control to each valve, there's a redundancy for overpressure control. The monitor valves are pneumatically operated valves. They do not depend on electric power. In case of control signal, these valves would close and, like I said, these means of controls are provided for both incoming and outgoing lines.

The three outgoing lines are operating under the same MOP. That's why they don't have additional controls. The lower two lines are operating at a lower MAOP so they have additional means of controls, which are again the regulator and the monitor valves.

In order to allow station maintenance or repair work, as well as in case of any abnormal operations, there is a station bypass, which is on the lower part of the slide, and the bypass is also provided with the monitor and regulator to prevent any overpressure on any of the lines in or out of the terminal.

MR. NICHOLSON: Okay. And the incoming lines, can you tell us what pressures those incoming lines can operate to maximum?

MR. KAZIMIRSKY: I don't remember the exact numbers, but they can operate, I believe, close to 500 pounds.

MR. NICHOLSON: That would be their maximum?

MR. KAZIMIRSKY: That's correct. But like I said, I don't remember the exact numbers.

MR. NICHOLSON: Would it help if we brought up 2-G, the Milpitas Station diagram? The operating system diagram.

Mr. Jones, could we get 2-G up on the overhead?

So I think 2-G actually lists what the maximum operating pressures are for those incoming lines; is that correct?

MR. KAZIMIRSKY: Yes, it does.

MR. NICHOLSON: And I see a MAOP as high as 600 for -- that would be Line 300B?

MR. KAZIMIRSKY: It may be. Like I said, I didn't remember the exact numbers.

MR. NICHOLSON: Okay. There are no compressors at Milpitas; is that correct?

MR. KAZIMIRSKY: No, there is not.

MR. NICHOLSON: So there's no way to boost pressure from Milpitas to Martin, the next station?

MR. KAZIMIRSKY: No. That is correct.

MR. NICHOLSON: The lines coming into Milpitas, do they initiate at compressor stations?

MR. KAZIMIRSKY: Upstream, some of them are; 300A and 300B initiate or go through the compressor station upstream at Kettleman.

MR. NICHOLSON: Okay. So they're boosted into Milpitas?

MR. KAZIMIRSKY: That's correct.

MR. NICHOLSON: And the control center has control of those stations as well?

MR. KAZIMIRSKY: Yes, they do.

MR. NICHOLSON: So from your previous description, you talked about monitor valves and the regulating valves. Which of those valves do the control center operators have authority over?

MR. KAZIMIRSKY: The gas control has the ability to manually position regulator valves, and they also have the ability to limit the opening of the monitor valves, but that will not override pressure controls. In other words, they can close the valves more than required by the pressure control, but they cannot open them more than required by that.

MR. NICHOLSON: They cannot open them more than the local set point?

MR. KAZIMIRSKY: That's correct.

MR. NICHOLSON: Okay. And what is the set point? What's a regulating set point? What's a monitor set point at Milpitas?

MR. KAZIMIRSKY: That set point can be anywhere below MAOP but never above MAOP. At Milpitas, it was set to 385 or 386, if I remember correctly.

MR. NICHOLSON: That's 386 on which valve?

MR. KAZIMIRSKY: On the monitor valves. 385 or 386.

MR. NICHOLSON: So the control center has control over the regulating valves. Is there any potential that the incoming line pressure could be seen, full incoming line pressure could be seen on the outgoing lines?

MR. KAZIMIRSKY: No, I don't believe so. Like I said, there is a redundant control there, and that pressure would be limited in two places at least.

MR. NICHOLSON: Okay. I want to now, if you could, discuss for us the work that was occurring on September 9th and how it led to the loss of power at the transmitters, and I'm speaking of Milpitas Station.

MR. KAZIMIRSKY: On September 9th, a construction crew began to work for replacing an uninterruptible power supply that failed early in the year in April of 2010. Part of the work was also to replace a power distribution panel. To mitigate the loss of controls capability as well as a loss of data to SCADA, the work included installing temporary UPSes for the critical components of the system. And if we could refer to slide 5 of Exhibit EA?

So when the work began, the crew got in touch with gas control and informed them of a potential loss of data as well as the work that would be performed at the terminal.

The next slide please. Correct.

The upper part of the slide shows what would be a normal architecture for the electrical system for the terminal. On the lower part of the slide, you can see the intermediate step while the UPS was being replaced. The temporary UPSes shown on the right side would provide power to the critical parts or critical components of the system while the primary UPS was being replaced. At the end of the work, the temporary UPSes would be replaced and the system would return to the architecture shown on the upper part of the slide.

The work progressed as scheduled and, around 4:30 or so, the crew completed the part of the work planned for that day and they informed gas control that they were done for the day.

However, sometime later, they noticed that they lost data from the pressure sensors used for the outgoing pressure -- or actually, for all pressure controllers. That was at about the same time as gas control started getting high pressure alarms on the discharge side of the terminal.

As the crew started troubleshooting, they found out that they lost 24-volt power supply supplying power to the pressure sensors, and they immediately began troubleshooting all the power supplies.

MR. NICHOLSON: I'm going to cut you off. Was it only a loss of power to the pressure transmitters or was it a loss of power to the controllers on the regulating valves as well?

MR. KAZIMIRSKY: No, that was only the loss of power to the pressure transmitters. The controllers were fully functional. However, the loss of pressure signals was interpreted by the controllers as a low pressure, which resulted in the controllers driving regulator valves to the fully open position --

MR. NICHOLSON: Okay.

MR. KAZIMIRSKY: -- which explains the increase of pressure on the discharge of the plant.

MR. NICHOLSON: So the regulators went wide open at that point because pressure was reading 0?

MR. KAZIMIRSKY: That's correct.

MR. NICHOLSON: And what about, there's also a shafting coder, I believe, that gives the SCADA operator position feedback on these regulating valves? Am I correct on that?

MR. KAZIMIRSKY: I don't remember if the position transmitters were affected by the loss of that power.

MR. NICHOLSON: Okay. By the regulating valves going wide open, did that trigger anything through the PLC or SCADA to the monitoring valves?

MR. KAZIMIRSKY: It triggered alarms to SCADA and also resulted in the monitor valves picking up a high pressure coming out on the discharge lines, and started throttling, bringing the pressure back down to their set points, about 385 psi.

MR. NICHOLSON: What did the loss of power do to the bypass valves? Was there some response of the bypass valves to the sensing of the regulating valves going 100 percent open?

MR. KAZIMIRSKY: It could have impacted the bypass valve as well in the same way. The bypass regulator valve could have gone open, but the monitor in the bypass would have done the same thing; it would have started throttling.

MR. NICHOLSON: But you've gone back at this point and examined the data to know if the bypass opened or not; is that correct?

MR. KAZIMIRSKY: We did. I frankly don't remember what position the bypass valve was open, but that was almost irrelevant in terms of discharge pressure.

MR. NICHOLSON: Why do you say that?

MR. KAZIMIRSKY: Because the set point for the monitor valve on the bypass is set to the same set point. So had the regulator gone open on the bypass, the monitor would have picked it up at the same set point.

MR. NICHOLSON: Okay. I want to explore that a little further then. Could we go, Mr. Jones, please to Exhibit 2-Y, page 116?

I've got a couple of control room transcript statements made that I wanted to have you maybe show us on the one line or your diagram.

MR. KAZIMIRSKY: It's probably easier on my diagram.

MR. NICHOLSON: Okay. They're referring to actual valve numbers. On this page, page 116, at 5:55 -- can you go up a little bit? It's right about right here, line 15. Here we have the Gas Control Operator saying, "Yeah, it should stay closed because we're showing almost 500 pounds downstream." And I believe he's speaking downstream of monitor valves 5 and 6. What I was hoping you could do for us was show us on the operating diagram where he's able to read that pressure and how it was protected from ever getting downstream, if he's seeing it at valves 5 and 6.

MR. KAZIMIRSKY: Well, I guess it's probably easier to see it on a simplified --

MR. NICHOLSON: Okay.

MR. KAZIMIRSKY: -- diagram that I --

MR. NICHOLSON: 2-EA, please, Mr. Jones.

MR. KAZIMIRSKY: There is a separate pressure transmitter for each regulator valve, including the bypass. So the pressures could be read for each line individually.

One slide up please.

The pressures could be read on each line individually as well as on the three valves that feed the discharge header and as well as bypass. As far as reading 500 pounds, that happened after the loss of the power supply and when the crew started the troubleshooting. So at that point, after the loss of the power supplies, all data was essentially unreliable because the crew was connecting/disconnecting different wires. They were pulling on the wires. So the numbers were kind of questionable at that time.

MR. NICHOLSON: Okay. So you're saying the 500 pounds he's referring to in those transcripts was an unreliable reading?

MR. KAZIMIRSKY: That's correct.

MR. NICHOLSON: Okay. And that was due to the power supplies failing?

MR. KAZIMIRSKY: That was due more to the troubleshooting activities that were going on at the station at the time. Some of the power was still available; however, due to the work of the crew, all data was unreliable.

MR. NICHOLSON: Okay. I'd like to go now to maybe the pressure trends that would talk to some of this as well. If we could get I think Exhibit 2-M, as in Mark, on the overhead, please?

And 2-M is actually the pressure transducer map, and maybe you could point out to us on this map where exactly these readings we're going to be looking at on the trends are taken. I know it's kind of a large map. What locations do we have pressure transducers at?

MR. KAZIMIRSKY: There are pressure transducers at every station shown on the map. Actually, there is even more readings along the line that are shown on slide, I believe, slide 1 of the same Exhibit EA.

MR. NICHOLSON: Okay. Can you tell me -- the rupture, I believe, is shown up north. Where -- let's see. What is the nearest station to that rupture that would have a SCADA pressure reading?

MR. KAZIMIRSKY: The nearest pressure upstream was Martin Station.

MR. NICHOLSON: And the Sierra Vista Crosstie, is that -- am I saying that correctly?

MR. KAZIMIRSKY: I think we may be better served by looking at the Exhibit 2-EA, slide 1. It shows more data.

MR. NICHOLSON: Okay.

MR. KAZIMIRSKY: But to answer your question, when Milpitas experienced problems, the data at all other stations along the pipeline were still as reliable as before. They were not impacted by any work at Milpitas.

MR. NICHOLSON: Okay. And what is the sampling rate on those transducers downstream?

MR. KAZIMIRSKY: I'm sorry.

MR. NICHOLSON: What is the sampling rate or the polling rate of those transducers downstream in Milpitas?

MR. KAZIMIRSKY: The transducers check the pressure continuously.

MR. NICHOLSON: So what's the refresh rate at the SCADA control center?

MR. KAZIMIRSKY: The SCADA may vary between 10, 15 to perhaps 40 seconds or so.

MR. NICHOLSON: Okay. Actually, I want to go at this point to the trends, I think. Let's cut ahead to Exhibit 2-EB, and we can -- leave this up, please, Mr. Jones. We'll come back to that as well. That is a good pictorial. So if you could get Exhibit 2-EB, page 2, I think we'll talk trends in conjunction with that map there.

Okay. So these are trends supplied by PG&E the day of the event, and I guess what I'm asking. Can we go to the next page please? Page 3.

I wanted to talk about these pressures here. If you scroll back to the left, you'll see we exceed 600 pounds on some of these readings. I've got the tag numbers there, Mr. Kazimirsky. If you could walk us through those trends. You're saying the 600, I believe, is not an actual pressure reading. Can you talk to that?

MR. KAZIMIRSKY: No, it's not. These readings were caused by the loss of power as well as perhaps some of the troubleshooting work done after that. And during the analysis following the accident, we were able to replicate the same readings by disconnecting different sources of power to the plant. So not only these numbers are unreliable, but we know for sure that they've been tested and they are unreliable, not to mention the fact that we could not have a pressure in the discharging plant higher than the pressure on the inlet since we don't have any compression capability there.

MR. NICHOLSON: Okay.

MR. KAZIMIRSKY: As far as pressure changing, a pipeline is a relatively slow, from a dynamic standpoint, object and it is impossible to change the pressure in the pipeline from 3-, 400 pounds down to 0 instantaneously as shown on these slides.

MR. NICHOLSON: You can't have a step change like that from 300 to 600?

MR. KAZIMIRSKY: No, absolutely not.

MR. NICHOLSON: Can we go back to that exhibit, please, Mr. Jones? That was 2-EB, and let's go back to slide I think it was 2 or page 2 on that.

And these will be the pressures, I believe, downstream in Milpitas that you say are reliable. So you pointed out that Martin, which is shown with the deepest descent there -- it's the purple line, if anyone can tell.

MR. KAZIMIRSKY: That's correct. That's following the rupture and, if I remember correctly, that pressure drop took several minutes to go from 380 or so pounds down to 50.

MR. NICHOLSON: Okay. Yeah, it looks like 386 there. Okay. And Half Moon Bay, is that anywhere near?

MR. KAZIMIRSKY: Not as close.

MR. NICHOLSON: The Sierra Vista Crosstie, what's shown in blue there, is that the next one downstream or upstream from the rupture?

MR. KAZIMIRSKY: It was upstream from the rupture and that's the reason the pressure there didn't fall as quickly as at Martin Station. Because following the rupture, Martin Station essentially lost its supply while the other stations upstream from the rupture were still fed.

MR. NICHOLSON: So we're backfeeding at that point? Is that what we're seeing?

MR. KAZIMIRSKY: No, Martin was backfeeding. All other facilities were still getting -- or stations were still getting gas from Milpitas.

MR. NICHOLSON: Yes, Martin was backfeeding --

MR. KAZIMIRSKY: That's correct.

MR. NICHOLSON: -- south towards the rupture. That's what you're saying?

MR. KAZIMIRSKY: Correct.

MR. NICHOLSON: Okay. I wanted to lastly with you, talk a little bit about the response time on those, the monitor valves at the station. They're pneumatically controlled, correct?

MR. KAZIMIRSKY: That's right.

MR. NICHOLSON: And they sit wide open normally?

MR. KAZIMIRSKY: That's correct.

MR. NICHOLSON: Could there have been a slug of gas that got through these things prior to their actually picking up downstream pressure and controlling?

MR. KAZIMIRSKY: I'm not sure what you mean by a slug of gas. The pressure doesn't change instantaneously. So as soon as the pressure started rising, as soon as the regulator valves started moving -- and they move fairly slowly as well; they don't open instantaneously. So as the regulator valves started opening and the pressure started rising, the monitor valves sensed the rising pressure and they started closing. So at some point perhaps these two valves were moving towards each other, if you will.

MR. NICHOLSON: So we do have a statement in the control room transcripts where they ask for a manual gauge to be placed downstream at, I believe, it was valve 49 on Line 132, and the reading on that gauge in the transcripts is 396 psi. That would be greater than the monitor's control pressure.

MR. KAZIMIRSKY: And the pressure did go above the monitor set points because, as you said, the monitor valves were wide open and it takes some time for the valves to close even when they sense the increased pressure. So the pressure could have gone, in fact -- it definitely went above the monitor set points. It never reached the MAOP, though.

MR. NICHOLSON: And you say that because of the downstream pressure trends we just looked at?

MR. KAZIMIRSKY: That's correct. As well as the data we got from the stations downstream from Milpitas. We never saw pressure either reach or exceed MAOP.

MR. NICHOLSON: Okay. Thank you.

I think we'll move on now to Mr. Chih-Hung Lee. If you would, Mr. Lee --

MR. LEE: Yes.

MR. NICHOLSON: -- tell us a little bit about your role at PG&E.

MR. LEE: I'm senior consultant engineer in the Integrity Management Group. My responsibility is to review all the pipeline being inspected for long-term integrity management plan.

MR. NICHOLSON: Okay. That's a review of each line segment?

MR. LEE: Yes.

MR. NICHOLSON: Okay. I'd like to, if we could, Mr. Jones, please bring up Exhibit 2-Q, pages 3 and 5. I want to talk to you today, Mr. Lee, a little bit about the policy memo that was written, I think it was 2006.

MR. LEE: Yes.

MR. NICHOLSON: This is the automatic control valve, remote control valve memo. If you'd scroll down a little farther?

Can you start by telling us what the purpose of that memo was, what it was meant to address?

MR. LEE: Yes. The memo was written for, internal memo for our integrity management review of pipe segments, and also to see whether there's a need for automatic shutoff valve or remote control valve specifically.

MR. NICHOLSON: And can you tell me who directed you to write this memo or --

MR. LEE: Our integrity management manager.

MR. NICHOLSON: Ms. Peralta that's here today or was this a previous manager?

MR. LEE: A previous manager.

MR. NICHOLSON: Was the content of the memo discussed or was it developed as a group effort or was this done by you alone?

MR. LEE: The memo was written by me and reviewed by our group, Integrity Management Group.

MR. NICHOLSON: And was this policy ever subject to review or has it remained as is since 2006?

MR. LEE: It has remained as is.

MR. NICHOLSON: Mr. Salas, are you aware of this policy memo?

MR. SALAS: Yes, I am.

MR. NICHOLSON: I'm sorry. I couldn't hear you.

MR. SALAS: Yes, I am.

MR. NICHOLSON: Okay. Did you sign off on it?

MR. SALAS: I don't recall signing off on it, but I'm aware of the memo.

MR. NICHOLSON: Okay.

MR. SALAS: Okay. I joined the company in 2007.

MR. NICHOLSON: So then you became aware of it when you started in 2007. Is that your first recollection of it?

MR. SALAS: Sometime over the course of 2007, but I don't remember specifically when.

MR. NICHOLSON: And at the time you believed that this policy memo was consistent with the safety philosophy stated in the Integrity Management Plan for PG&E?

MR. SALAS: I believe that the policy had been reviewed, analyzed, and that the conclusions were reasonable.

MR. NICHOLSON: And I want to read for you what that says in case -- are you familiar with the philosophy statement in the -- the safety philosophy statement of the Integrity Management Plan?

MR. SALAS: Feel free to read it, but I am familiar with it.

MR. NICHOLSON: Okay. And I just want to be sure you understand the passage I'm looking at, and that's "to deliver services at the lowest possible cost without compromising safety and environmental compliance."

MR. SALAS: Correct.

MR. NICHOLSON: Okay.

MR. SALAS: Our mission is to not compromise safety or the environment and to do that efficiently.

MR. NICHOLSON: So, Mr. Lee, the last sentence of the introduction of your memo states that, "This document provides the review of ASV and RCV literature and establishes company guidelines for consideration of ASV and RCV installation." Can you tell me how you went about identifying the literature used for this memo?

MR. LEE: This memo, in my reference material, the memo, the study of remote control valve and automatic shutoff valve by Gas Research Institute, by Pipeline Research Council International, and by INGAA, Interstate Natural Gas Pipeline Association of America.

MR. NICHOLSON: And you think that reasonably covered all the existing literature on this subject?

MR. LEE: At that time, yes, I think so.

MR. NICHOLSON: Did you consider the 1999 DOT, Remotely Controlled Valves on Interstate Natural Gas Pipelines document?

MR. LEE: I have read that, yes.

MR. NICHOLSON: You did? Okay. You read it at the time you were doing your literature search for this?

MR. LEE: Yes.

MR. NICHOLSON: Okay. And why wasn't that incorporated as a reference?

MR. LEE: I don't remember.

MR. NICHOLSON: Okay. So I'd like to actually go to page 72 of that document. If you could bring up, Mr. Jones, this would be Exhibit 2-Q; it should be page 72. Scroll down. 2-Q, please. I need the statement.

Can you read for us please the highlighted section there?

MR. LEE: Yes. "At many locations there is significant risk as long as gas is being supplied to a rupture site and operators lack the ability to quickly close existing manual valves. Any fire would be of greater intensity and would have greater potential for damaging surrounding infrastructure if it is consistently replenished with gas. The degree of disruption in the heavily populated and commercial areas would be in direct proportion to the duration of the fire."

MR. NICHOLSON: Thank you. And I just want to contrast that to item 3, page 1 of your memo which states, "The duration of fire has little or nothing to do with human safety and property damage." Can you just let me know or explain for us how those two statements are reconciled in your document?

MR. LEE: Yes. Those documents are from industry study result conclusions.

MR. NICHOLSON: So you're saying they're industry conclusions. So they're independent of DOT's conclusions?

MR. LEE: Energy study show most majority damage within 30 seconds of the time of the rupture.

MR. NICHOLSON: Okay. So if I'm hearing you correctly, your policy memo did not look at the Department of Transportation study; it relied only on industry studies to establish the basis of policy on ACVs?

MR. LEE: Yes.

MR. TRAINOR: What specific industry references are you referring to?

MR. LEE: Listed in my reference.

MR. TRAINOR: I would ask you to identify them, please.

MR. LEE: *Design Rationale for Valve Spacing, Structure Count, and Corridor Width*, by Mr. Eiber, Pipeline Research Council International study.

MR. TRAINOR: Are there other references that you used?

MR. LEE: Yes. *Development of the B31.8 Code and Federal Pipeline Safety Registration* [sic]*: Implication for Today's Natural Gas Pipeline System*, Gas Research Institute paper.

MR. TRAINOR: Do any of these references -- well, let me ask you this. Do both of these references conclude that, as you put it, most of the damage is done within the first few minutes of a release?

MR. LEE: That is correct.

MR. TRAINOR: Do either one of these references address continuing and prolonged damage if the release is sustained?

MR. LEE: No, I don't remember.

MR. TRAINOR: Well, couldn't it be true then that really the damage assessment of a prolonged release of gas is not addressed in either one of these documents?

MR. LEE: I have to review these documents again for details.

MR. SALAS: If I might be permitted to add, Mr. Trainor. We, as a matter of policy, have placed automatic and remote control valves within our system. We do so in very specific applications. We've done them at compression stations, pressure limiting stations, storage facilities. We do it over seismic faults where we feel that there's a risk that could be mitigated by the use of the automatic or remotely controlled valve in addition to bridge crossings.

What we've done since this terrible tragedy is step back, and given the historic methods for analyzing the benefits of the use of this technology, concluded that while it's difficult to prove analytically, that we think that there's sufficient basis to deploy aggressively increased levels of automations in our pipeline, and we've got work underway right now to do so. So our policy has shifted.

MR. TRAINOR: Well, that has been since the accident, as you state.

MR. SALAS: Yes, sir.

MR. TRAINOR: Okay. Prior to the accident, was population density a factor or considered in the placement or use of remote control valves or automatic valves?

MR. SALAS: It was analyzed in the paper that you've been referencing, and I also think that the valve spacing criteria, I believe that PHMSA defines, also plays a part with regard to safety.

MR. TRAINOR: All right. One other question for Mr. Lee.

MR. LEE: Yes.

MR. TRAINOR: In this accident, it took approximately an hour and a half to close the two manual valves to isolate the rupture. If remote valves had been in those locations, what would have been the time it would have taken those valves to activate and isolate the break?

MR. LEE: The time involved activating the automatic valve or remote control valve, it has to be -- because the pipeline are interconnected and then the signal has to be reviewed correctly by control before even -- even the signal confirmed, we, in this case, we have people on the ground to verify the rupture section to identify which specific valve need to be closed. That's the time would be considered, and also even we shut off the valve right at the location we had for the closest men involved is still going to take more than 10, 15 minutes.

MR. TRAINOR: But those actions you just described would be things that you would also do with a manually operated valve.

MR. LEE: That is correct.

MR. TRAINOR: So that's a wash. What I'm saying is once the decision is that you need to close these two specific valves, it took 90 minutes for a crew to get to those valves and shut them down. What is about the approximate time it would take to close and have a remote valve close and isolate that line?

MR. LEE: Actually, our crew got to the site within, I believe, less than one hour, or one hour time, and then the time to shut it off, the time we decided to shut it off --

MR. TRAINOR: Let me put it this way. Would it take 60 minutes to 90 minutes for a remote valve to close?

MR. LEE: No.

MR. TRAINOR: Would it take 30 minutes for a remote valve to close?

MR. LEE: No.

MR. TRAINOR: Would it take 15 minutes for that remote valve to close? Once the decision had been made to activate that valve, would it take 15 minutes for that valve to close, a remote valve?

MR. LEE: To shut off the valve, yes, we could shut off the valve sooner with --

MR. TRAINOR: How much sooner? Can you give me a ballpark figure?

MR. LEE: Probably a half hour.

MR. TRAINOR: Thirty minutes? You just said a moment ago it wouldn't have taken 30 minutes. I'm trying to get a sense of the time here, and where I'm going with this is that for the time it took to close the manual valves, several -- 35 million plus cubic feet of gas were released. The amount of gas that would have been released is proportional to the time the gas was flowing to that pipeline. If you could cut the time it took to isolate that break by 50 percent, it would have reduced the amount of gas released by the same amount, and so forth.

Now what's the difference between releasing 3-1/2 million cubic feet or 10 percent of what was released versus 35 million cubic feet? Would the impact upon the community be greater in the latter case?

MR. LEE: I don't know. According to the industry study, most of the damage happened within a very short period of time.

MR. TRAINOR: I'm not arguing that point. I'm arguing about the extended or prolonged release of gas. We heard Mr. Chhatre's opening statement that within 15 minutes after the manual valves were closed, firefighters were able to get into the scene. Would it have made a difference to the community of San Bruno if the firefighters would have been able to get into that scene in 15 minutes as opposed to 90 minutes?

MR. LEE: I wasn't involved in the --

MR. TRAINOR: Thank you.

MR. LEE: -- case study. I don't know.

CHAIRMAN HERSMAN: Mr. Lee, you can go ahead and answer the question. I think that there's two primary questions that Mr. Trainor's trying to get at and we may be having a -- kind of talking past each other. I think we're trying to figure out the impact of the release, you know, short duration versus prolonged, and how long it would take for an automatic valve to shut down. What would that process take? And I think we're spending a lot of time on this question and I think we might just be talking past each other a little bit.

MR. SALAS: Madam Chairman, if I could answer maybe at a broader level?

CHAIRMAN HERSMAN: Microphone, please.

MR. SALAS: I think in theory, clearly, if there had been automated valves in the sites that were closest to the rupture site, I think it's clear that we would have, in theory, assuming telemetry worked, assuming communications work, and the power was not interrupted, we would have been able to actuate those valves. Having said that, I have no ability to know whether the sites in question could have been upgraded or modified to accommodate the technology for automation. So it really depends on where the valves are in response to, in relation to a rupture site, to determine what the duration or the save time might have been or could have been. And that's one, you know, for us to I think make some assumptions about and then do the analysis.

With regard to the amount of damage that might have been avoided given the time it took to close the valves, I don't think we have the analysis yet from this investigation that would quantify precisely what that impact might have been.

MR. NICHOLSON: And also I think Mr. Slibsager could probably weigh in on this little bit as far as control room response and how quickly. Because in this case, we know that it was roughly, what, 5 to 8 minutes that your control team, the SCADA gas operators had identified a rupture? If they had had that ability to remotely close, wouldn't that have sped up?

MR. SLIBSAGER: Yes. I would like to say, and I'm sorry I wasn't able to get in the conversation earlier, gas control is familiar and is comfortable in using remote control valves, and as such, had we had remote control capability on those two manual valves, gas control, after doing the proper analysis, which may have taken 10 minutes or so to look at the hydraulics of other surrounding SCADA points -- as shown in the earlier slide, there are a number of other additional monitoring points on that San Francisco Peninsula that would have ultimately collaborated the data at Martin Station that, in fact, there was an event there that involved the transmission pipeline. And we could have closed remote control valves and they would have actuated, as Mr. Salas said, rapidly providing all the equipment at that station performed as necessary.

MR. NICHOLSON: And as far as leak detection is concerned in the control center, what's the ability -- how tight of a resolution do you get on leaks, if you can see them at all? Do you have flow meters between stations, intermediate locations? How does that work?

MR. SLIBSAGER: We have the ability to monitor the entire SCADA system, which is large, and on the San Francisco Peninsula alone, you saw the number of sites on the screen earlier that we are able to monitor. So those represent pressure, additional pressure information as well as flow information. So upon alarm, which would be our first signal of information that might represent a leak or some sort of an event, we would look at that additional data through those other flow meters and pressure sites to begin to see if the hydraulics -- and typically you would see pressure continue to decrease on other sites and flow meters increase on sites to show you at the operator level the hydraulics that would exhibit a leak.

MR. NICHOLSON: So I would expect if PG&E does not have remote control valve capability, then they must have a fairly robust leak detection system built in, either hydraulic models or intermediate flow meters. Can you -- I mean, what do you have as far as flow meters? Just Martin and Milpitas?

MR. SLIBSAGER: There are some intermediate flow meters on that Peninsula system as well, and we rely on our SCADA system to provide knowledge to the operator of events that could be happening on our pipelines or have taken place on our pipelines.

MR. NICHOLSON: I'm going to jump back to Mr. Lee for just a moment because you did say, and I think Mr. Salas backed you up on this, that there are instances where automatic, or ACVs, automatic closing valves or remote closing valves might be installed and, in fact, your memo supports that saying that one of those cases, at least, would be across a fault line. Is that correct?

MR. LEE: Correct.

MR. NICHOLSON: And when I'm reviewing the long-term Integrity Management Plan for this portion of Line 132 --

MR. LEE: Yes.

MR. NICHOLSON: -- it talks about two fault crossings on this line of Line 132, the San Andreas Fault, in fact. I think crossings at milepost 38 and 37.86 on Segment 178.05. Can you tell me if there are RCVs on those locations?

MR. LEE: For earthquake fault crossing, pipeline fault crossing we have a program to review the pipeline per the earthquake fault information. Our goal is to prevent the pipeline from rupturing. So we have a program put in place prioritized all the fault crossing review and replacement. I think those two are currently in our current year review and study. In the past, we have replaced several fault crossings for our pipelines.

MR. NICHOLSON: So the answer's no; there's no ACVs or RCVs at those two locations currently or before September 9th?

MR. LEE: That is correct.

MR. NICHOLSON: Okay. Thanks. I'm going to pass this on to Ravi Chhatre at this time.

MR. CHHATRE: Mr. Lee --

MR. LEE: Yes.

MR. CHHATRE: Mr. Lee, if I may ask a follow-up question on your memo?

MR. LEE: Yes.

MR. CHHATRE: 2-Q, page 5, please. Can you bring it down? Okay. That's good enough.

In this memo, your objective is to look at the automatic shutoff and remote control valves and evaluate the suitability. What I'm wondering is, all the literature you searched, couldn't you find a single advantage of these valves?

MR. LEE: The automatic shutoff valve and remote control valve mitigate the consequence. It didn't show they can prevent rupture or have any major impact on the damage. And the advantage from all the studies show that mostly it's from operation purpose, and the saving, it's the reduced gas release time.

MR. CHHATRE: The reason I'm asking is your memo lists all the limitations of these valves, but I don't see any positive sides in the memo, and that was the reason for the question. So I'm just wondering if the literature in the industry is you didn't find anything or somehow that thing was not mentioned.

MR. LEE: In the cost-benefit study, it shows almost like the installation cost compared with the gas saved is like

20:1, and I didn't quote it in there.

MR. CHHATRE: And the other question regarding this memo, I'm kind of a little bit trying to clarify myself, the leak or it says ruptures, and is PG&E using these terms in this memo, as a policy memo, those two terms interchangeably, leak or it says ruptures? If you look at the paragraph on that memo.

Can you have the 2-Q, page 5 again, please? If you go up a little bit. Right there. That's fine.

Released gas when pipeline ruptures, and underneath that, if you come down to item 4, I believe, it mentions leaks, that leaks will not trigger ASVs. I'm a little confused why the leak discussion is in rupture unless you are using it interchangeably. I'm just trying to clarify in my mind what the memo means.

MR. LEE: That was one of the things mentioned in the industry report, study, and -- because the usefulness of the automatic shutoff valve really doesn't apply to leak. You have to set a certain level for its trigger. So if we set a level of that kind, then it will trigger intentionally during operating condition. So the leak will not be one of the benefits or a safety measure for automatic shutoff valve.

MR. SALAS: If I could add one other point? The configuration and architecture of our system is not a long linear interstate pipeline. We are a local distribution company with a highly networked and intertwined system that layers transmission, local transmission and distribution pipes. So the complexity of putting technology into that system is I think elevated from just simply thinking we can place technology and it can be effective. What we need are advances, I think, as we deploy the technology we're committing to deploy and program logic and monitoring and control system so that we can manage systems coherently. Low pressure systems are as hazardous to the public as overpressure systems, and we need to have tools in place that manage all of this technology really well, and I think more work needs to be done.

MR. NICHOLSON: Maybe Mr. Kazimirsky could talk to some of the technical difficulties in installing remote closing valves on these lines. Is there some sort of hurdle to installing these?

MR. KAZIMIRSKY: In many cases there are. Many of these valves or many of the valves that we have now, manual valves, in the populated areas, are under the sidewalks, perhaps under the roadways, and in order to automate these valves, they may need to be relocated. There's also, especially in California, there's a very lengthy permitting process. There are also technical difficulties because the valves would need either pneumatic or electric actuators which in turn would require either a high pressure gas or electric power. That's as far as the valves themselves are concerned.

As far as automatic valves, I'm not aware of any technology that is available right now specifically for a line rupture detection. We are looking into that. We are trying to find if such technology exists. I know it didn't exist several years ago.

We're also looking at perhaps developing a technology like that for the automatic valves, but we are looking at installing these valves. We have a pilot project for this year. We're going to install, I believe, about a dozen valves. We're also looking at what other utilities are using in terms of automated valves, and we're doing the benchmarking. We're trying to figure out if there are applications that we can perhaps utilize within our system.

MR. NICHOLSON: Okay. Thank you.

Going back to Mr. Lee's memo, and the DOT report, I would just like to get a comment on a couple of conclusions in that report. Mr. Jones, if we could go to 2-Q, page 81 and 82. And let's see. What page is that? Page 82. Scroll up to 81 please, Mr. Jones.

These are actually PG&E's responses to that DOT report in '99, and we've highlighted some passages there, and I just wondered, Mr. Lee, were you aware of the comments made to the report when you did your review?

MR. LEE: Yes.

MR. NICHOLSON: And basically PG&E's comments to that report were that they have no objection to installing RCVs and have found them reliable. And I'm just wondering, that kind of speaks again your conclusion where they're not recommended for general mitigation measures, and I wondered if you could balance those two statements.

MR. LEE: We have a internal PG&E expert reviewing all the technology of automatic shutoff valve and remote control valve, and the conclusion is the automatic shutoff valve, we do -- the memo that I quote in my reference, I think that has still a problem, but remote control valve, we are confident that we can install in terms of the technology-wise and no problem.

MR. NICHOLSON: So your preference is remote control valves --

MR. LEE: That is correct.

MR. NICHOLSON: -- over automatic shutoff valves?

MR. LEE: That is correct.

MR. NICHOLSON: We were talking earlier about response times, and there is definitely a time to recognize a rupture and to understand where it's located, and I wondered if you had a guideline at PG&E, what that time should be in a class 3 or 4 location?

MR. KAZIMIRSKY: At this point, I don't know.

MR. NICHOLSON: There's nothing internal at PG&E on that?

MR. KAZIMIRSKY: No.

MR. NICHOLSON: So if there was a response from PG&E to PHMSA in 1999 -- I'll point you to Exhibit 2-DU, page 5, and, in fact, PG&E recommends one hour to isolate class 3 and 4 and two hours in class 1 and 2. Does that seem like a reasonable amount of time, Mr. Slibsager, for a control room response?

MR. SLIBSAGER: PG&E's control room response upon activation of an alarm is a first indication of an event transpiring on our system and not all alarms actually lead to an actual event to taking place on the system. The operator is essentially -- initially acknowledges that alarm. It essentially stops the flashing and the audible nature of the alarm, and then they begin to start doing an analysis on that alarm, and the analysis would be to look, as I said earlier, those corresponding sites for some sort of collaboration that that event is actually taking place.

As a result of that, if they come to the conclusion through their analysis that the alarm is, in fact, truly a system condition or our facilities are involved, they will do callouts to the local areas for response, but they also have the capability, and they do employ the capability, the operators, that is, to actually use their remote control equipment to attempt to bring the abnormal situation back towards a normal situation.

In an event such as the Milpitas loss of data and subsequent increase in pressure they saw, they did go to the upstream stations and begin to lower those. Those pressures we indicated earlier that had maximum capability of 550 to 600 pounds, they used their remote control equipment to start bringing that pressure down.

The callouts are usually done in concert with that because, generally speaking, we can use the remote equipment to bring the situation near normal but we ultimately need crews out to actually check the facilities and repair the equipment that's actually broken, or in the case of some sort of leak or line rupture, they will need to be there to actually perform the manual isolation of the site. And that actually transpires over a period of time of -- you know, we think it's normal to at least need 10 minutes to do the analysis and have the hydraulic setup occur on SCADA. But we will do it as quickly as possible if we get indication, and then it will be another period of time for the crew members to actually be able to respond to the site depending on traffic conditions and whether they are home or not and need to report back to their work location to get their proper tools and equipment to do that.

MR. NICHOLSON: So I thought I heard you say in that statement that the gas controllers can call out to emergency responders directly?

MR. SLIBSAGER: The gas control operators have the ability to call the local crew members that perform the maintenance on the transmission system.

MR. NICHOLSON: Oh, okay. So they can only call out to other PG&E employees?

MR. SLIBSAGER: Oh, I'm sorry. Correct, yes.

MR. NICHOLSON: Okay. So not -- they can't call 911?

MR. SLIBSAGER: No, they do not do that.

MR. NICHOLSON: And why is that?

MR. SLIBSAGER: Our practice has been to get PG&E employees on site to understand what the conditions are. It's basically boots on the ground, eyes on the situation to understand what's taking place and what the event is.

MR. NICHOLSON: So I want to refer you then to the control room transcripts. That would be Exhibit 2-Y, page 268, and there's a passage in there where the gas controller is actually talking to field personnel trying to decide who's going to isolate this, whether it can be done at the control center or out in the field. I'm just wondering, can you talk to the control room's role and responsibility in an emergency, and specifically September 9th?

MR. SLIBSAGER: The control room's responsibility -- and I'm not clear I understand your question. I mean, I've stated how, basically, the analysis is done and then calling of crew members. So beyond that, I'm not sure I understand what you're asking for.

MR. NICHOLSON: So can the control room isolate? Do they have the ability to shut off Milpitas, shut off Martin?

MR. SLIBSAGER: No. I'm sorry --

MR. NICHOLSON: How does that work?

MR. SLIBSAGER: -- I didn't understand. Yes, wherever we have remote control capability on the pipeline, which is primarily used for pressure set point control, to actually change the pressure in the pipeline, those regulation set points can actually be used to essentially put the pressure to zero and have the valve actuate towards the closed position, and we have a number of valves we can close.

In that particular case, yes -- well, let me clarify. At Milpitas, there was an interruption of the data. So we did not have remote control capability, but we did have crew members there, and we could have instructed them to close the valves at Milpitas manually through that troubleshooting effort. But I believe, having done that, would have created a much more widespread public safety issue, had actually the operators instructed the crew members to just shut down the valving at Milpitas and having that be the control measure taken to evacuate the gas ultimately through the entire San Francisco Peninsula network of pipes.

There are three transmission lines that were transporting gas to the San Francisco area, many numerous, you know, small interconnections into the distribution system, into the communities and areas, and that safety event I think would have, you know, precipitated, you know, pilot lights going out in the homes of all these residences that live in that area, and ultimately if, through that process, low pressure gas had migrated back into those homes, that would have been an unsafe condition.

This is a very vast area, incorporating parts of Santa Clara Valley and the County, as well as San Mateo County and the City and County of San Francisco. Millions of people are connected to that pipeline system, including many facilities such as hospitals, nearly 130 of them, 365 senior care facilities --

MR. NICHOLSON: Okay.

MR. SLIBSAGER: -- and so forth.

MR. NICHOLSON: All right. So you think there would have been a bigger hazard to them actually shutting down Milpitas?

MR. SLIBSAGER: Well, there would have been, and also it would have taken in excess of 2 months to relight all those customers and bring them back into service, and I think that might have rendered some people not able to live in their homes in that situation.

MR. NICHOLSON: But now the control center did isolate Martin downstream of the rupture; is that correct?

MR. SLIBSAGER: That is correct. It's another remote site on that system, and that was done so once we had field verification and a full understanding of the pipeline event. And as a crew member at the upstream site began to isolate at Mile Point 38.49, he actually radioed into the control room and asked them to close down Martin Station as well performing that isolation.

MR. NICHOLSON: Right. So they could have done that much sooner but your procedure doesn't allow that because you want a supervisor or someone else on scene first?

MR. SLIBSAGER: We need to have an eye on the situation and understand it fully. At the time, you know, you're talking about, it was a period of 15 to 30 minutes, and as that was happening, there was a lot of conflicting data or definitely uncertain information coming into the control room about potential for a gasoline station to have exploded, a jetliner having come down in the area, and it takes some time for the control room to understand that information, and having our employees on site actually giving those visual feedback allows us to take the correct remote operation move.

MR. NICHOLSON: We saw that in the transcripts. There was a lot of talk about an airplane crash, and there was some confusion in the control center. Does that impede the response efforts and should it? If you have a line break, shouldn't you respond either way?

MR. SLIBSAGER: Well, we always treat every situation as its real until we can confirm that it's not. I'm not sure I would characterize there being confusion as much as a lot of uncertain information coming into the control room that had to be confirmed. And through that process of working with our own internal first responders throughout the PG&E company, we were able to establish that we were involved and it was our facilities, it appeared in all likelihood, whether it was as a result of some other event or a pipeline rupture. We then began to take action.

MR. NICHOLSON: Okay. Back on ASVs, RCVs or remote close valves. Ms. Peralta, if you could maybe start by giving us a little background in how long you've been at PG&E, at least as manager of integrity management.

MS. PERALTA: I've been with the company a little over 8 years now, and prior positions with the company have included field engineer in support of the external corrosion direct assessment program. I was also a project engineer in support of that same program. I was also a transmission and regulation supervisor in the field overseeing leak survey, corrosion control, regulation involved maintenance, and I've been manager of the Integrity Management Program for a little over a year and a half now.

MR. NICHOLSON: Okay. And as manager of integrity management, you were aware also of Mr. Lee's memo, his policy statement on --

MS. PERALTA: I was aware.

MR. NICHOLSON: Okay. In fact, were you cc'd or did you sign off on that as Manager?

MS. PERALTA: The 2006 memo, I was not the manager of integrity management at that time.

MR. NICHOLSON: And you didn't have to re-review it in 2009?

MS. PERALTA: I have reviewed that in my time. Yes, I have.

MR. NICHOLSON: Okay. Can you tell me, it seems like within the risk management program, there's weightings and risk evaluations for particular threats to the pipe, but I don't see how an ASV/RCV is assessed within the risk management program. Is there a procedure similar to the other threats for determination of when an ASV/RCV is to be used?

MS. PERALTA: No, there is not.

MR. NICHOLSON: So the policy statement by Mr. Lee is just a blanket statement?

MS. PERALTA: It's not a blanket statement. An evaluation was done by Mr. Lee. He integrated the data that is listed in the sources and the footnotes of the letter, and that is the conclusion that we came to at that time.

MR. NICHOLSON: Okay. And I think in the conclusion or the final parts that memo, it says it will be looked at as a case-by-case basis, and I guess I'm trying to see where the procedure is for that case-by-case. Is it somewhere in risk management?

MS. PERALTA: We do not have a procedure for the case-by-case basis but, as we've discussed, we are fully looking into the use of this technology in our system.

MR. NICHOLSON: That's now. There was nothing before then, before September 9th though. You're evaluating now, right?

MS. PERALTA: That is correct.

MR. NICHOLSON: Okay. Mr. Chhatre.

MR. CHHATRE: Mr. Salas, PG&E has a nuclear power plant and how does your pipeline integrity management inspections compare those pipelines, compared to the natural gas pipelines?

MR. SALAS: I'm not familiar specifically with how Diablo Canyon Nuclear Power Plant manages their risk management processes other than my understanding of the nuclear industry is that they use probabilistic models as it relates to assigning risk values to their infrastructure.

MR. CHHATRE: Do you know if there's any collaboration of information or program or practices between the nuclear side of the company and the natural gas site of the company?

MR. SALAS: We have dialogue but there isn't a specific formal forum to, I think to share that sort of operating practice. We do in many other regards as relates to other safety practices, although I will say that we are -- again as we look periodically at re-evaluating our integrity management and risk management programs, look to make improvements. And one of the things that we are doing is attempting to migrate from the relativistic model, which was referenced by Mr. Nicholson, to a probabilistic model in terms of how we are going to be looking forward in managing the calibration of threat and risk.

Having said that, a probabilistic model is only as good as the data that you have to form the basis of it, and to the extent as an operator I don't have really good empirical data on faults and failures that cut across the entire nation or globe, it either strengthens or weakens the validity and the effectiveness of such a program. I think it's an opportunity for us to get better as an industry.

MR. CHHATRE: Now, Mr. Salas, was Line 132, to your knowledge, ever identified to senior management as a critical line item in the operations budget and as an at-risk line?

MR. SALAS: Not specifically. All transmission lines, all high consequence lines, are viewed as priority lines.

MR. CHHATRE: Now, the Integrity Management Program is designed to protect the pipelines. There were lines, according to your risk program, have a higher risk identified than Segment 180 that ruptured; however, Segment 180 is the one that ruptured. How confident do the Integrity Management Program people feel or you as the vice president feel, confident about the program?

MR. SALAS: Clearly something went wrong. So we're re-evaluating our program. We're re-evaluating the notion of threats and where they come from. I think the metallurgical reports cause us to step back and think seriously about the whole notion of double submerged arc weld quality. Up to this point in time, it's been viewed as really the gold standard for long seam welds and it hasn't been identified as a weld category that would cause us to do further analysis or assessment of. So to the extent the findings here point towards issues with regard to these, I think that's a fairly significant development for the industry.

MR. CHHATRE: I'm reminded that we are overdue for a break. So, Lorenda, we can go either way. We can just continue or come back.

HEARING OFFICER WARD: Madam Chairman, can we take a break at this point?

CHAIRMAN HERSMAN: Okay. We're a little bit behind schedule. So we'll go ahead and keep with our 20-minute break. It's 11:00. We'll reconvene at 11:20, and we will start promptly.

(Off the record.)

(On the record.)

CHAIRMAN HERSMAN: If everyone could take their seats please, we're about to resume.

Welcome back. We're reconvening for the resumption of the Technical Panel to conclude their questioning of the first panel. At this time, I would like to acknowledge that we do have two officials from San Bruno who are here with us, and they're sitting at the San Bruno table. We have Mayor Jim Ruane. If you would stand up, please? And we also have Council Member Rico Medina here with us, too, who is in the audience. Thank you all very much for being here. We do recognize how difficult this has been for your community. We hope that this hearing will provide you a window into the investigative process.

Technical Panel, are you ready to resume with your questions?

MR. CHHATRE: We are.

CHAIRMAN HERSMAN: Please proceed.

MR. NICHOLSON: Ms. Peralta, I would like to talk to you a little bit about MAOP right now, and if you would, please go ahead and define for us what maximum allowable operating pressure is on a gas transmission pipeline.

MS. PERALTA: Sure. Per the Code of Federal Regulations, maximum allowable operating pressure, or MAOP, is the maximum pressure that a pipeline segment or system is authorized to operate at. For PG&E, in accordance with that definition, we define maximum allowable operating pressure to be the maximum pressure that a pipeline segment can operate at. We also define the term maximum operating pressure, or MOP, to be the maximum pressure that a pipeline system can operate at, and this pressure, this MOP is governed by the lowest MAOP. So because the Code of Federal Regulations uses MAOP to define both a system and a segment definition, we have developed this nomenclature to differentiate between the two.

MR. NICHOLSON: Okay. And if you would, what factors go into calculating the MAOP?

MS. PERALTA: If you are indeed calculating the MAOP, the factors would be diameter and wall thickness and strength.

MR. NICHOLSON: And what was the MAOP of Line 132?

MS. PERALTA: 400 pounds per square inch.

MR. NICHOLSON: And was that different than the MOP?

MS. PERALTA: So if I can use Line 132 as an example to illustrate our definitions of MOP and MAOP, and if I could pull up Exhibit 2-EA, slide 1, please?

So there is a lot of information contained on this slide. What I'd like to point out is Line 132, in addition to Line 109, which go from Milpitas to San Francisco. So Line 132 and Line 109, they are connected hydraulically. They share the same gas as they move up the Peninsula system. So while they are connected, the MOP, which is the system definition I provided, of Line 132 is limited by 109. So the MOP of Line 109 is 375 pounds per square inch. If you isolate those pipelines, which we could do in the case of a clearance process or something else, the MOP of Line 132 is 400, which is equivalent to its MAOP.

MR. NICHOLSON: Okay. Thanks.

When you talked about calculating it, you mentioned diameter, wall thickness and yield stress were all factors. If you don't have those parameters, what methods are available to you for establishing MAOP?

MS. PERALTA: So there are three methods for establishing maximum allowable operating pressure. One is where you calculate it as we have discussed. One is where you pressure test it in accordance with its application, where that pipeline will reside, be it in an urban or suburban environment. And the other option is the historic operating pressure, and this would be the highest pressure that the pipeline experienced during the years of 1965 and 1970, and for Segment 180 on Line 132, this would have been 400 pounds per square inch gauge as indicated in our 1968 document.

MR. NICHOLSON: And that's actually Exhibit 2-C. If we could go to that, Mr. Jones, please, 2-C, page 2.

So I heard hydro test, calculated method and highest operating pressure prior to?

MS. PERALTA: Between the years of 1965 and 1970.

MR. NICHOLSON: And that is how Segment 180 was qualified?

MS. PERALTA: That is correct.

MR. NICHOLSON: Okay. And this document, 2-C, when it comes up, is the document, I believe, that was supplied giving us that. I think it's page 3. Keep going. It might be page 4. And let's try page 5, Mr. Jones.

Okay. So can you tell me on this sheet here that was used to establish its MAOP, how long it was held at that pressure?

MS. PERALTA: I apologize. I'm having trouble deciphering the legibility of this document but it is the highest pressure indicated on this record.

MR. NICHOLSON: It's the highest pressure, but do you know how long it was held at that pressure?

MS. PERALTA: I do not know.

MR. NICHOLSON: Is that information available elsewhere?

MS. PERALTA: I am not aware if it is.

CHAIRMAN HERSMAN: If there's some information that's requested that you may not have with you, and you do find it, we'd appreciate if you'd follow up and you could just provide it to us for the record, okay?

MS. PERALTA: Absolutely.

CHAIRMAN HERSMAN: Thank you.

MR. NICHOLSON: Can you tell me if Line 132 has ever been hydrostatically pressure tested, any parts of it?

MS. PERALTA: So while the majority of Line 132 was established using the highest pressure experience between the years I described, as new construction takes place, pressure testing is conducted before putting lines into service as part of our construction process.

MR. NICHOLSON: That's on new construction? Did I hear that correctly?

MS. PERALTA: That's correct.

MR. NICHOLSON: But has any part been hydro tested of Line 132, any of the existing segments?

MS. PERALTA: I do not believe so.

MR. NICHOLSON: If they had, is that indicated on the survey sheets?

MS. PERALTA: If it was done as part of the Integrity Management Program, it would be indicated in the assessment field in GIS.

MR. NICHOLSON: It would be in GIS. So wouldn't that populate the survey sheets under Test Date?

MS. PERALTA: So the pipeline survey sheets are a graphical representation, if you will, of what is contained in our

GIS database.

MR. NICHOLSON: And, in fact, on Segment 180, Line 132, there is a test date on the survey sheet. I believe it says 1961.

If we could have -- I think that's Exhibit 2-P, page 9 or page 10. You should have those exhibits there. Do you not have the survey sheets?

MS. PERALTA: I do not have --

MR. NICHOLSON: Nancy, is it possible to get them, Exhibit 2-P?

That's it there. We'd have to zoom in a little bit for you to be able to see Segment 180. Okay.

MS. PERALTA: Thank you.

MR. NICHOLSON: That's pretty good. And you'll see that the second category of rows there under pipe data would be test data and the first line is date, and if you scroll to the right, Mr. Jones, please, so that we get Segment 180? Continue please. The segments are at the very bottom.

Okay. So there's Segment 180, listed as it was, seamless, 42,000 yield. It's showing there a test date, I think, of 1/1/1961. Can you talk to that?

MS. PERALTA: I cannot speak to that.

MR. NICHOLSON: Okay. Am I reading that correctly?

Mr. Daubin, you're free to chime in if you can answer this.

MR. DAUBIN: Mr. Nicholson, I believe that states 1956 for Segment 180.

MR. NICHOLSON: No, I'm not looking at that. You're in the wrong -- I'm looking at the test data. If you move your cursor up, Mr. Jones, to the line that reads 1961?

There's actually a hyphen I think on Segment 180 in that. There you go. That's the line. So doesn't the [-] mean that we continue that year over?

MR. DAUBIN: Yes, sir, it does.

MR. NICHOLSON: Okay. So my question again is can you talk to -- that looks like a test date for Segment 180. Can you tell me how that test was performed?

MR. DAUBIN: To the best of my knowledge, I believe that was done with -- it was not a hydro test. It was a pressure test.

MR. NICHOLSON: To what pressure?

MR. DAUBIN: I do not know.

MR. NICHOLSON: Okay. Ms. Peralta, have you looked at or examined the materials lab factual reports?

MS. PERALTA: I have.

MR. NICHOLSON: Okay. Then you're aware that it talks about weld quality and various yield strengths?

MS. PERALTA: I am.

MR. NICHOLSON: Can you tell me what the impact would be on Segment 180 as a result of the findings from that report, as far as MAOP, or maximum allowable operating pressure, is concerned?

MS. PERALTA: So while there were low strengths indicated in some of the pups in the metallurgy report, we did not calculate MAOP for this segment. What's important to note is that those strengths are for the plate steel and the rupture did not initiate in the plate steel, as we know from the report. It initiated along the long seam of pup 1. And this is very significant because this long seam --

MR. NICHOLSON: I'm sorry. I'm going to cut you off there. Can you talk to maximum allowable operating pressure as it would be calculated as a result of those findings? Would it be greater, lower?

MS. PERALTA: So the maximum allowable operating pressure would be lower, but that is not how the MAOP was established for this pipeline.

MR. NICHOLSON: Okay. So, yeah, there was no requirement for calculation on that line.

MS. PERALTA: That's correct.

MR. NICHOLSON: Thank you. Has anyone in your group established whether or not this segment would have failed during a hydro test based on the material lab factual reports?

MS. PERALTA: I think it's misleading to state -- we cannot definitively state that this would have failed during a hydro test.

MR. NICHOLSON: Why can you not definitively state that? We have lower yields. We have wall thickness.

MS. PERALTA: That's correct. So I'd like to point to two other examples in our recent industry where there were two pipeline failures in other operators' companies along the long seam. Both of these pipelines had experienced hydro tests as well as inline inspection, including the use of a crack tool which is capable of detecting long seam defects.

MR. NICHOLSON: Okay. That's, that's fine. Thank you.

And that's not quite what I was asking. I was asking has anyone looked at whether or not this pipeline would have failed under a hydro test?

MS. PERALTA: We would need the metallurgy results of the long seam, and I believe that we do not have those, in order to fully model the situation that you're talking about.

MR. NICHOLSON: Okay. Thank you.

Regarding the 5-year policy, can you explain PG&E's policy of running Line 132 to MAOP ever 5 years?

MS. PERALTA: So the planned pressure increases that are done every 5 years, if these values are not reached through normal operations, are part of the Integrity Management Program and they deal specifically with specific lines within the program.

MR. NICHOLSON: I'm sorry. They deal with specific lines and the segments?

MS. PERALTA: That's correct. We do not do this on all of the lines.

MR. NICHOLSON: Okay.

MS. PERALTA: These are lines where we have identified a stable manufacturing threat, and when I say manufacturing threat, that's a term of art that's used in industry to describe certain types of long seam issues that are known to exist in industries such as low frequency electric resistance welded pipelines.

MR. NICHOLSON: So you actually raise the pressure up to MAOP to --

MS. PERALTA: It's not necessarily MAOP. It's the 5-year -- it's the 5-year high in the prior -- it's the 5-year maximum operating pressure, which may be MAOP but it could be something less.

MR. TRAINOR: Ms. Peralta, the manner in which MAOP was calculated for Line 132 --

MS. PERALTA: If I may -- I'm sorry, not to interrupt. If I may, sir, it was not calculated.

MR. TRAINOR: Well, established.

MS. PERALTA: Right, it was established.

MR. TRAINOR: The manner in which MAOP was established, is that by virtue of the age of the pipeline?

MS. PERALTA: So generally, yes, I should have stated in my earlier comment that that's for pre-'70 installations pipelines.

MR. TRAINOR: Okay. And how many transmission lines does the company operate?

MS. PERALTA: We have approximately 5700 miles of transmission pipeline in our system.

MR. TRAINOR: And what percentage of those miles of pipeline were constructed prior to 1970?

MS. PERALTA: I don't have that exact figure, but we can get that to you.

MR. TRAINOR: Do you have any transmission lines that have been constructed since 1970?

MS. PERALTA: Many.

MR. TRAINOR: And again, do you have the mileage on that, on those lines?

MS. PERALTA: No, but I can get that for you as well.

MR. TRAINOR: Okay. For post-1970 construction, how was MAOP determined for those lines?

MS. PERALTA: So it is designed in accordance with its application. So we test the pressure based on the tables in 192.619(c) and it includes a safety factor which is determined where the pipeline will be in terms of class location.

MR. TRAINOR: All right. Would post-1970 determination include the material properties and strengths of the pipe?

MS. PERALTA: Yes, it would.

MR. TRAINOR: Of the components?

MS. PERALTA: Yes.

MR. TRAINOR: Of all valves and fittings?

MS. PERALTA: Yes.

MR. TRAINOR: Pressure ratings?

MS. PERALTA: Yes, that's included as well.

MR. TRAINOR: Going back to pre-1970 construction, when you determine MAOP for these lines, is it based upon previous operating pressures within the line?

MS. PERALTA: Yes, it is.

MR. TRAINOR: Are there any other considerations to MAOP for pre-1970 lines?

MS. PERALTA: We choose the pressure based on our operating records that we have which indicates a safe pressure that the pipeline had operated at during those 5 years.

MR. TRAINOR: Okay. And when you test the line every 5 years, the pre-1970 lines, what's the duration of time the pipeline is operated at MAOP?

MS. PERALTA: So when we do the planned pressure increases, and sometimes just through regular operations, the pipeline will reach its 5-year maximum operating pressure, in which case there's no need, but when we conduct these planned and monitored increases, it's held for approximately 2 hours.

MR. TRAINOR: Thank you.

MR. NICHOLSON: Okay. Thank you, Ms. Peralta. I'll pass this on to Mr. Chhatre.

MR. CHHATRE: Ms. Peralta, you mentioned earlier answering to Mr. Nicholson's questions, that the reason you raise this pressure to MAOP only on certain lines because of the known risks?

MS. PERALTA: I did not say the known risks. I said these lines have identified a stable manufacturing threat.

MR. CHHATRE: Okay. Can you elaborate on that, on what was the case for Segment 180, Line 132?

MS. PERALTA: So Segment 180 is not -- let me see. Segment 180 would not meet the criteria in terms of this 5-year maximum operating pressure. This is specific to pipes that are known to have seam issues, deficiencies with their long seam introduced during the manufacturing process, and Segment 180, which we believe to be double submerged arc welded pipe, that is not a long seam concern that is considered in industry at this time.

MR. CHHATRE: Could you identify which threats caused PG&E to raise the pressure every 5 years on Line 132?

MS. PERALTA: So it's the manufacturing threat as it applies to pre-1970 ERW pipeline or those joint efficiency factors that are less than .8.

MR. CHHATRE: Okay. Can you tell me precisely which of those factors apply to Line 132, because apparently Line 132 was raised to 400 psi?

MS. PERALTA: It was raised. That is correct. And I believe both of those factors apply to Line 132.

MR. CHHATRE: And those two would be? Can you repeat those one more time for me, please?

MS. PERALTA: Low frequency ERW pipe, which is pre-1970, and joint efficiencies less than .8.

MR. CHHATRE: Okay. And where those low frequency ERW pipe segments will be in Line 132?

MS. PERALTA: I don't know their exact location.

MR. CHHATRE: Okay. Are those close to Segment 180?

MS. PERALTA: I don't believe so.

MR. CHHATRE: Okay. I'm going to move on to risk algorithms in RMP-1, if you would, and there are several items in that binder that includes RMP-1 through 13. And if I'm correct, the committees are supposed to meet every year. Can you tell me, did all the committees meet every year and, if they did not, how much the lag was?

MS. PERALTA: So the consequence committee did not meet every year. I believe the likelihood committees met every year since I've been the manager of integrity management.

MR. CHHATRE: Now, looking at the document for the risk management, on the first sheet, it identifies what revisions were made and there are lots of gaps, 2, 3 year gaps on that. Does that mean the committees did not meet or what happened? If I'm looking at the binder, how do I know what happened there?

MS. PERALTA: Right. So the cover sheet on our risk management procedures indicates the dates that those procedures were revised. So the procedures are reviewed and if there are revisions made, then they are revised and that sheet reflects not the reviews and the revisions, but just the revisions that are made.

MR. CHHATRE: I'm going to go back to again RMP-1 where the program says top 10 pipelines selected as high risk based on the two parameters you use. One is the probability of failure and the consequence of ruptures. And these numbers are given some kind of arbitrary value. My question is, what is the basis for selecting 10? Where did the number 10 come from?

MS. PERALTA: So the purpose of selecting segments is to validate through the threat committees the results that the algorithm is producing. So this number was selected, and it's used for discussion purposes when the threat committees convene for us to check and validate whether we're getting the results that we would have expected to get in our program.

MR. CHHATRE: Now, obviously, Segment 180 didn't make that cut. How confident you as a manager are on the algorithm that's identifying the high risk pipes?

MS. PERALTA: So Segment 180 was identified as a high risk pipe, and when I say high risk, again these are terms of art in industry which do not mean that the high risk segments are going to fail. I know that that's tough to accept in the context of our conversation, but it means -- you know, risk analysis is a way of focusing our attention on the pipelines that most need them. So it's a tool that we use on prioritization. And so that's what the intention of our risk analysis is. And so Segment 180 was identified as a high risk segment, which is why we assessed it within the first year, really, of our program in 2004, and we reassessed it in 2009, which was 2 years earlier than its scheduled reassessment.

MR. CHHATRE: Are there any segments on Line 132 made that top 10 cut?

MS. PERALTA: I don't know that question exactly, the answer to that question. I'm sorry.

MR. CHHATRE: Can you please get that to us when you go back?

MS. PERALTA: I can.

MR. NICHOLSON: When you say Line 132, Segment 180 was high risk, can you tell me how it was classified as high risk? Was that likelihood of failure, consequence of failure? Can you elaborate, please?

MS. PERALTA: Sure. Both factors go into our risk equation, both likelihood and consequence. And in our PO6, the original authors developed some statistical analysis to do to identify which pipelines would be treated as high risk. And again, the purpose of identifying a segment as high risk is for prioritization within the Integrity Management Program. So Segment 180 was identified as high risk and it was addressed, not only in the first half of our program, but in the first year of our official program.

MR. NICHOLSON: I'm sorry. So are you saying that was a numeric relative risk ranking that put it in high risk category?

MS. PERALTA: That's correct.

MR. NICHOLSON: Okay. Because I don't see it. When I go through Line 132, 2009-2010 risk rankings, I don't see it in the top, as a top 10 item.

MS. PERALTA: Right. In our risk management procedures, you can have basically demerits. You know, you can have points that negatively impact the risk and you can also take credit for mitigation items. So if you look in the 2004 baseline assessment plan when Line 132, the high consequence risk was initially calculated, you will see it as a high risk segment. But because we performed subsequent assessments through external corrosion direct assessment and applied the mitigation plans to this line and this segment, it has reduced the risk over time.

MR. NICHOLSON: What mitigation measures were taken on Segment 180?

MS. PERALTA: So on Segment 180 specifically, the results of the external corrosion direct assessment show that there was not corrosion on this pipeline or coating damage and the results, at least in terms of the corrosion, were validated through the metallurgic report. But we have replaced -- we have done pipeline replacement, significant, on 132 as well as recoating. We've done a number of excavations all to --

MR. NICHOLSON: I'm sorry. Are these specific to Segment 180?

MS. PERALTA: They are not specific to Segment 180, sir.

MR. NICHOLSON: Okay. Only Segment 180, what mitigation techniques were used?

MS. PERALTA: As a result of the 2004 inspection survey, we raised the rectifier outputs on that line because the off potentials, if you will, during the close interval survey were slightly below -850 millivolts opt. We raised them and we did see the positive effects of that on our 2009 survey.

MR. NICHOLSON: Is it true that hydrostatic testing is a mitigating factor under your risk management program?

MS. PERALTA: Yes. Yes, it is.

MR. NICHOLSON: Thank you. I'll pass this on to Mr. Chhatre.

MR. CHHATRE: Hi, Ms. Peralta. I'd like to refer you to your earlier testimony of January 6, 2011. And can you please get the Exhibit 2-BI, page 52-53.

And while that is coming up, let me ask you a question which doesn't require the exhibit, and the question is, how does the high consequence area -- is rated in this algorithm? Are all high consequence areas rated the same irrespective of the population within them?

MS. PERALTA: I'm sorry. Is that a question?

MR. CHHATRE: Okay. Let me rephrase it. If I have two different segments on Line 132 and both are ranked as HCA, one only has 20 dwellings in the impact circle, the other has 200 in the same area, in your algorithm, will both those locations have the same rate when you calculate the risk?

MS. PERALTA: So I think I understand the question. So we run two different risk analyses and risk rankings. One's for the entire system, which deals with HCAs and non-HCAs, and then we do a separate risk calculation as it relates to consequence of failure specific for high consequence areas, and one of the factors in the consequence, the HCA consequence calculation is PIR, is the potential impact ratings.

MR. CHHATRE: Right, but I don't believe you answered my question. My question still is when you take HCA ranking, HCA within two different segments, when you do the calculations for your risk analysis, do both those segments have the same rating, both being in HCA?

MS. PERALTA: No, because the potential impact radius could be different along our pipeline, and so that's what's taken into consideration in the consequence portion of our HCA analysis.

MR. CHHATRE: Okay. I'll move on and get to the exhibit. Can you go down, please? Go further down. Can you go to page 52-53?

When the director of integrity management asked you a question during that interview, you answered, looking at -- can you go down further? Okay. Go up a little, line 52 -- page 52 -- line 19 through 11. Okay. Right there.

"So based the definition of potential impact circle, is it fair to say that there isn't an impact to society outside of that circle according to this definition?" Can you see that?

MS. PERALTA: I can see that, yes.

MR. CHHATRE: Okay. And my question is, based on the circumstances in San Bruno, in your opinion, is this still a valid assessment?

MS. PERALTA: So this is taken a little bit out of context of a larger discussion, and I believe there was some confusion in that discussion about what was exactly being asked. So I don't think what I stated to you previously here is in conflict with what I stated there.

MR. CHHATRE: How would you consider different populations in different HCAs into your algorithm when you rank them for risks? Can you elaborate that?

MS. PERALTA: The method that we use to calculate high consequence areas is method 2, and by definition of using method 2, we do consider population densities around our pipeline. So we essentially draw a circle around our pipeline, which is a function of the diameter and the pressure, and then we count structures that fall within the circle. And so we are concerned when we are calculating HCA about what is around our pipeline, the environment, being density of structures or the type of structures.

MR. CHHATRE: Okay. I got you.

MS. PERALTA: Okay.

MR. CHHATRE: Let me ask another question and that will be my last one for you, and I'll pass it on to Matt. In your 2009 Integrity Management Plan says -- well, Line 132 states that internal corrosion was not considered a threat. And we recognize that no internal corrosion was observed in the ruptured segment. My question is liquids were found and detected in Line 132 during the camera inspection.

MS. PERALTA: I'm sorry. Can you repeat that last statement again?

MR. CHHATRE: Sure. Post-accident camera inspection revealed liquids in Line 132.

MS. PERALTA: Okay.

MR. CHHATRE: With that fact, can you explain and elaborate how and why internal corrosion would not be considered a risk factor for Line 132?

MS. PERALTA: So internal corrosion is identified as a threat, if you will, on Line 132, and we have performed ICDA on this entire Peninsula network, and the results of the camera inspection that you're referring to I think are best explored with the Integrity Management Panel this afternoon.

MR. CHHATRE: Thank you for that, and I'll pass on to Matt.

MR. NICHOLSON: I want to be sure I heard you correctly. You said internal corrosion was a threat to Line 132?

MS. PERALTA: For certain segments on Line 132, yes.

MR. NICHOLSON: Segment 180, was it a threat?

MS. PERALTA: I do not believe so.

MR. NICHOLSON: Which means there was no internal corrosion program?

MS. PERALTA: We did apply ICDA, internal corrosion direct assessment to the Peninsula pipeline system, which included Line 132, and we did --

MR. NICHOLSON: I'm asking about Segment 180 in particular.

MS. PERALTA: It was included as we analyzed that entire pipeline for internal corrosion through the direct assessment process.

MR. NICHOLSON: Okay. Thank you.

Mr. Daubin, I'd like to talk to you a little bit about the GIS database and the information in it. It's been stated to the NTSB that this Segment 180 pipe was most likely manufactured by Consolidated Western over several years, 1948, '49 and '53. Can you explain how this conclusion was drawn or how you arrived at that information?

MR. DAUBIN: Certainly. If you can go to Exhibit 2-EC, please, specifically slide 7.

While I'm waiting for that to come up, I can talk a little bit about -- in regards to Line 132 specifically, Segment 180, there's been an extensive records research done for Line 132. We also carried that through for all pre-1962 30-inch pipe. We reconciled the pipe purchases to three purchase orders, and I apologize for the error in the slide. It says over 100,000 feet of 30-inch pipe was purchased. That is true for one of those purchase orders. All three purchase orders totaled about 238,000 feet of 30-inch pipe. Those three purchase orders you see there were originally established for Line 153, Line 131 and Line 132, over those years that you had mentioned. We determined all possible vendors for that era.

MR. NICHOLSON: Can you tell me, Mr. Daubin, when was this extensive search done? Before September 9th or post-September 9th.

MR. DAUBIN: This was done post-September 9th.

MR. NICHOLSON: Thank you.

MR. DAUBIN: Would you like me to continue?

MR. NICHOLSON: Please.

MR. DAUBIN: Okay. We determined the possible vendors for that area. We narrowed that down to three potential vendors. Through further analysis we determined that the manufacturing sequence was consistent with one manufacturer, as well as the identified brand and the diameter stamp was also consistent with that manufacturer that was noted in the metallurgical report.

MR. NICHOLSON: So the contention is that all the pipe used for the 1956 relocation was purchased pipe; is that correct?

MR. DAUBIN: We believe it to be pipe that was purchased on those three purchase orders during the year 1948.

MR. NICHOLSON: Could any of it have been salvage pipe from the original project, 1948 project?

MR. DAUBIN: It could have been, but again that would have fallen under those three original purchase orders.

MR. NICHOLSON: When you have the three purchase orders with multiple years on them, how was that accounted for by the Integrity Management Group?

MR. DAUBIN: I would have to refer that specifically to the Integrity Management Group, but --

MR. NICHOLSON: Ms. Peralta, can you answer that?

MS. PERALTA: Can you repeat your question please?

MR. NICHOLSON: Yes. And I'm speaking specifically to the survey sheet, and you pointed to it earlier. If we go back to the survey sheet, it says year installed 1956, but a record search by Mr. Daubin has revealed that this is actually pipe that spans multiple years. I'm wondering, how was that taken into account with integrity management? Are you looking at this as 1956 pipe or are you considering the multiple years that it consists of?

MS. PERALTA: So GIS, the field in GIS reflects the date of installation. However, through the Integrity Management Program, we do pull job records in support of that program and we verify the information that is contained within them, which would include when the pipe was purchased.

MR. NICHOLSON: Okay. So going back to pre-September 9th, Line 132, Segment 180, was it analyzed or was the risk assessed taking into account that it had multiple years of pipe, multiple manufacturing years?

MS. PERALTA: No, it was not.

MR. NICHOLSON: So it would have all been done in the context of a 1956 installation?

MS. PERALTA: That is correct.

MR. NICHOLSON: Okay. Mr. Daubin, do you want to talk a little bit about how this particular segment of pipe, Segment 180 got listed as seamless into the GIS system?

MR. DAUBIN: Certainly. So within that same Exhibit 2-EC, if you can go to slide 1.

Specifically talking about Segment 180 on Line 132, we were shown to be 30-inch seamless in PG&E's geographical information system. So through that records research that we had spoken about earlier, we determined that in 1977, the pipeline survey sheets were created. That was an exhibit that you had shown earlier. The project folder documentation which is the document of record was used to create those pipeline survey sheets.

In 1998, a little after GIS was initiated, the GIS system utilized the pipeline survey sheets to populate its dataset specifically for Segment 180. And going further back and utilizing the project folder documentation, we believe that the information that was pulled off of the documents in the project folder were taken from what is known as a journal voucher. The documentation was used inaccurately, which reflected the pipe as being 30-inch SML, and that was taken at the time that the pipeline survey sheets were created as being seamless.

MR. NICHOLSON: That's actually shown on the next slide, I believe, if you could go one more.

MR. DAUBIN: That is correct. Slide 2 of the same exhibit.

MR. NICHOLSON: Mr. Jones. Thanks.

MR. DAUBIN: The top half again is kind of a cut-away version of our specific materials and specifications catalog that shows the specific material code associated with 30-inch double submerged arc welded pipe, specifically double wrapped. That material code is in the journal voucher document. However, the journal voucher document's description denotes it as SML pipe, which is an inaccurate statement.

MR. NICHOLSON: So what makes you think a 1967 material codes list is an accurate assessment of a journal voucher from 1956? What makes that a coherent --

MR. DAUBIN: We worked with our sourcing department to determine if those codes were valid. Historically, changing those codes is very difficult because of the implications of said change, and those codes have rarely changed. We worked with our sourcing department to determine if they had.

MR. NICHOLSON: So this code looks like it's tied to not only yield strength and grade, but a wall thickness and a wrap. Is that right?

MR. DAUBIN: You say this. What are you referring to?

MR. NICHOLSON: I'm looking at your circled item. It's been taken down. The item you circled in the material codes list, what a typical material code would consist of, wall thickness?

MR. DAUBIN: Correct.

MR. NICHOLSON: Okay. So we've looked at documents from 1960 that use this same 1373 code on journal vouchers and the description on those is 5/16th wall.

MR. DAUBIN: And I believe those documents that you're referring to are also journal vouchers.

MR. NICHOLSON: Okay. But they use that material code, right?

MR. DAUBIN: Agreed. Just as this journal voucher refers to that same material code as 375 SML, which we know does not exist.

MR. NICHOLSON: So journal vouchers are not a valid --

MR. DAUBIN: That is correct.

MR. NICHOLSON: -- document for populating GIS? Okay. I'll pass this on to Mr. Chhatre.

MR. CHHATRE: Mr. Daubin, on Line 132, especially Segment 180, we found several pups which are shorter in length. I believe they probably don't even meet PG&E's code of minimum 5-feet long pups. My question is have you done any search on other PG&E lines? How do you ensure that the other lines, especially 101 and 109, may or may not have these kinds of pups present?

MR. DAUBIN: If you're asking in regards to what measures have we taken, we have done extensive validation efforts of our records, specifically using the engineering specifications and material codes associated with those pipelines for the Peninsula lines. We're continuing to undergo that very same effort for the remainder of our transmission line. Thus far, we have not found any abnormal short sections. And when I -- the reason I am careful on qualifying abnormal is because oftentimes shorter sections, or pups as they're called, will be used on a pipeline in normal construction practices, say, around transition pieces to either valves, reducers, those types of things.

MR. CHHATRE: If I understand you correctly, all this is still a literature search, document search, which have been questioned under current circumstances. My question is has PG&E done any verification digs at the location where you see pups or there could be pups, and verify how your record matches with the documents?

MR. DAUBIN: Again, we have not seen any abnormal areas where those pups would be --

MR. CHHATRE: I'm sorry. That is not the question. The question is has PG&E done any digs on any of the 101 and 109 lines where you do see pups, done a dig to verify to make sure your document matches with the conditions in the field?

MR. DAUBIN: I'll have to take your question in two pieces. PG&E has done many different validation digs specifically related to pre-1962 30-inch pipe. We have done several validation digs and where we would do radiography of the long seam to confirm the long seam, long seam pipe.

MR. CHHATRE: Would that be post-September 9, 2010?

MR. DAUBIN: Yes, sir.

MR. CHHATRE: Can you tell me how many and where?

MR. DAUBIN: I'm sorry. I don't have the exact number, but I have --

MR. CHHATRE: Can you provide that?

MR. DAUBIN: I can get the number and locations for you.

MR. CHHATRE: Can you provide that at a later date?

MR. DAUBIN: I can get the number and locations for you.

MR. CHHATRE: Thank you much.

MR. TRAINOR: Mr. Daubin. Mr. Daubin --

MR. DAUBIN: Yes, sir.

MR. TRAINOR: -- the efforts that you were just describing a moment ago, was any of this work done prior to September 9th?

MR. DAUBIN: Was this work done prior to September 9th?

MR. TRAINOR: Was any of this research effort and excavation work and so forth that you were just describing done prior to September 9th?

MR. DAUBIN: Not for the items that we were specifically looking for, but as a normal course of routine maintenance through the Integrity Management Program, which I believe the Panel 2 can speak to far greater than I could. We do several validation digs throughout the course of the Integrity Management Program.

MR. TRAINOR: We'll address that in the next panel.

MR. DAUBIN: Okay.

MR. TRAINOR: Thank you.

MR. NICHOLSON: One final question to you, Mr. Daubin, then. If I'm looking at not a journal voucher but a material procurement order with a material number, is that a valid document?

MR. DAUBIN: It is not necessarily an engineering specification or bill of material in which we would use.

MR. NICHOLSON: Okay. Thank you.

MR. CHHATRE: Madam Chairman, the Technical Panel has concluded its questions.

CHAIRMAN HERSMAN: Thank you. And we are running a little bit behind. We'll try to stay on schedule and so we'll reconvene at 1:00. We'll take a 54-minute break for lunch.

(Whereupon, at 12:06 p.m., a lunch recess was taken.)

A F T E R N O O N   S E S S I O N

(1:00 p.m.)

CHAIRMAN HERSMAN: Welcome back. We will begin the second part of the panel questioning with the Technical Panel. Are there any additional questions from the Tech Panel for Panel 1?

MR. CHHATRE: No additional questions.

CHAIRMAN HERSMAN: Okay.

MR. CHHATRE: Thank you.

CHAIRMAN HERSMAN: We'll move to the Parties and since all of the witnesses are PG&E witnesses, you will have the opportunity to ask the questions last. So we'll begin with PHMSA.

MR. WIESE: Madam Chairman, thank you very much.

CHAIRMAN HERSMAN: Mr. Wiese, I'm sorry. Before you begin, if I could just remind all the Parties, there are some lights up on the table, and you'll see they're green, yellow and red. And we're going for 5-minute rounds for all the Parties as well as the Board members, and you'll get a yellow about a minute -- when you have a minute left, and a red when you've hit your time. And so I'd prefer for you to self-police, but if not, I will jump in.

And also I'd like to remind the Parties, please don't ask any questions that might ask the witnesses to perform analysis or draw conclusions or probable cause. I will try to cut that line of questioning off. We're really here just to get some facts from them, and so ask them about what they're prepared to respond on. Thank you.

MR. WIESE: Okay. Well, I'm relatively sure there will be a few snickers here in the crowd. I will stay within my 5 minutes. I've got a couple of quick questions for you. I'm interested just in broader issues, and so I leave it to you who to respond to. I don't know precisely who has that background.

The first question I have relates to procedures, particularly those that could affect SCADA systems. And I was just curious what your procedures call for when you're doing work that could affect the SCADA system, whether it was testing new software or doing electrical work that could, you know, affect the SCADA system in some way.

MR. KAZIMIRSKY: The usual procedure is to create a work request or clearance informing gas control of the work being done or planned to be done, to get the approval from gas control, have all steps of the work described in that procedure. We would also have all of the required drawings and documentation prior to doing the work and we would have a commissioning or task procedure prepared for the work. Depending on the complexity of the work, that procedure may be more or less detailed, but that will be a normal construction and commissioning procedure.

MR. WIESE: I'd just point out that PHMSA had done an advisory a number of years ago that relates to SCADA systems and work that could influence SCADA systems. Not immediately and directly relevant, but clearly any work that you do that affects your ability to monitor your system in any way is something you want to take seriously, as I'm sure you do.

The next question really is just, the 5-year pressure increase that you had talked about as a practice, I'm just curious if PG&E continues that practice at this time?

MS. PERALTA: That practice is no longer. We are no longer conducting that practice and we are in the process of re-evaluating our entire manufacturing threat criteria, including what pipelines fall into it as well as what affects the stability of that criteria.

MR. WIESE: Okay. Thank you.

Probably amongst my last questions really is, our questions really relate to the broader industry. We're interested in what you learn and your ability to learn and reflect that in changes to your operating practices and your procedures. So I just welcome any general comments about your Integrity Management Program or other parts of your system, whether it's an overpressure event or a failure, how do you learn from that and ensure that you can continuously improve the caliber of your operations?

MR. SALAS: We've got an entire body of work. A lot of it is directed by the normal course of the investigation, and so in the course of the investigation, as we find opportunities to make process improvements or the like, we move on those. In addition to that, quite frankly, we don't need to wait for a root cause analysis to have been completed to say that there are things that we could continue to improve upon like our integrity management or risk management programs. And so we have launched work in those areas, actually work that had already been in process to make those necessary improvements. And then, again, we're stepping back and looking at the whole notion in terms of how we think about pipe condition versus age and criteria for replacement. So we're looking aggressively not only at technology, but also with regard to the asset and the criteria that we might use for replacement.

MR. WIESE: Okay. Last question, just a yes or no. Do you have an informal management of change process so that -- you know, it affects your procedures and then your training and everything else to ensure that you can execute it?

MR. SALAS: Yes, we have change management processes.

MR. WIESE: Great. Thank you.

CHAIRMAN HERSMAN: Thank you. IBEW.

MS. MAZZANTI: No questions at this time.

CHAIRMAN HERSMAN: City of San Bruno.

MS. JACKSON: Yes, thank you. I have a question for Mr. Salas. First, given the identified defects in the welds in the failed section of Pipeline 132, will automatic shutoff or remote valves now be installed to address these new threats both in Line 132 as well as the other lines that traverse San Bruno, Lines 101 and 109?

MR. SALAS: There's two nuances to the question. I guess the first easy answer is we are going to be deploying remote and automated control valves in our system. We're evaluating where that's going to have the greatest benefit or affect as relates to our high consequence area, and we're in the process of working with PHMSA and other regulators to help inform the new design criteria that we intend to propose. Having said that, we're going to pilot aggressively this summer the placement of some valves, just to make sure that we're clear about process.

As it relates to the specific root cause of the failed pipe in question, we're going to wait until we have all the facts and conclusions for probable cause from the NTSB before we commence any mitigative action as it relates to that.

MS. JACKSON: Just a quick follow-up question. The new valves that you'll be piloting this summer, will any of those be installed on the lines that I mentioned in San Bruno?

MR. SALAS: We are evaluating all of the lines on the Peninsula. I can't tell you specifically where we would seek to pilot, but I would imagine 132 would be one of those places.

MS. JACKSON: Great. Thank you. Mr. Slibsager, it took a long time to confirm to your satisfaction the location of the rupture and then to shut down the line. In light of that situation, will additional pressure monitoring equipment be installed in the pipeline to help operating personnel more quickly identify the location of a pipeline failure and more quickly initiate actions to shut down and isolate the failed section?

MR. SLIBSAGER: In answer to your question, we have already added additional monitoring sites as a result of some reconfiguration efforts we had to take on to continue to serve the customer base during the winter months, and we are looking at improvements in the area in our study of adding remote control valves to our system that would allow us to do a more effective isolation sooner.

MS. JACKSON: Great. And these are specifically on Line 132?

MR. SLIBSAGER: That is correct.

MS. JACKSON: Thank you.

Ms. Peralta, you mentioned earlier the process in establishing the MAOP or maintaining the MAOP at 400 pounds related to the every 5 years increase in the pressure and maintenance at that pressure for a period of about 2 hours. What exactly are you looking for during that 2-hour period? What are you observing and what are you monitoring and what might be the result of that pressure increase?

MR. SLIBSAGER: So what we're doing during that pressure increase is exactly what you say. We are monitoring the pressure to a very specific value, and this is on these lines that may not have reached this 5-year maximum operating pressure during their normal course of operations because they could have reached it on their own just by meeting customer demand. So we are looking exactly at pressure. Is that responsive?

MS. JACKSON: Maybe you could describe to me what is the indication of the ability of the pipeline to maintain the pressure then, I guess would be my question. Are you looking for a leak or how might the pipe behave in that situation that would either satisfy your interest or give you rise to additional concerns?

MS. PERALTA: So the pressures that we are raising the pipeline to are the maximum allowable operating pressure or something less, and I should state that the maximum allowable operating pressure is a pressure with significant safety factors built in already. You know, the pipeline is tested to a much greater pressure when it's manufactured at the mill. There's also reductions that are taken, you know, restrictions based on what we call class location. So raising that pressure up to the pressures through these planned increases is not a cause of concern. It's a routine operation conducted on the pipeline.

MS. JACKSON: Okay. Thank you.

MR. SALAS: If I might just add?

MS. JACKSON: Please.

MR. SALAS: We would be monitoring for any reduction in pressure which would indicate that perhaps we have a leak and then we would take action to diagnose that.

MS. JACKSON: Great. Thank you very much.

CHAIRMAN HERSMAN: CPUC.

MR. CLANON: Thank you, Madam Chair. Panel, I'm Paul Clanon. I'll be representing the Public Utilities Commission.

Just a quick follow up. You've now been asked questions I think by everybody about the 5-year policy, and we've heard about the criteria that you use to select the lines that you apply it to. We've heard what you're looking for when you're doing that, I'll call it a test, and we've heard that you're not doing it anymore. I want to get to the question of why you were doing it? And I wonder if I could have Exhibit 2-AI up?

So let me just direct the question to Ms. Peralta. If you could just sort of generally tell us why was that PG&E's policy? What were you trying to accomplish?

MS. PERALTA: So through the 5-year maximum operating pressure increases, if the pipeline has not seen that 5-year maximum operating pressure -- I think it's probably maybe best to use an example to illustrate the point. If you have a maximum allowable operating pressure of, say, 400 pounds in the pipeline, but you operate it over the course of the next 5 years at 300 pounds, if it has not raised through the course of operations to 400 pounds -- the pressure's now 300 pounds, and if you go another 5 years and say your pressure doesn't operate at more than 150, then that becomes your new maximum operating pressure. So over time, your pressure would eventually go to zero essentially in the pipeline, I mean, if you follow the logic through.

MR. CLANON: And that's as an operation of PHMSA rules or that's an operation of an interpretation of the Federal Regulations?

MS. PERALTA: An interpretation of 192.917.

MR. CLANON: Thanks. And do we have that exhibit? If we don't, that's okay. Just the next page, please.

MR. JONES: What page are you referring to?

MR. CLANON: Can I have the next page, please? A little bit down.

And this may be what you just said, but I just want to have you read that paragraph, the second paragraph under answer 5, and just make sure that that's the understanding you were just giving us.

MS. PERALTA: Would you like me to read it?

MR. CLANON: Silently, please.

MS. PERALTA: Okay.

MR. CLANON: And just tell me if you still agree with that. I only have 5 minutes.

MS. PERALTA: I would agree with that paragraph.

MR. CLANON: And one of the things that you're saying here in this paragraph is that there is an alternative to the ratcheting down effect that you mentioned, and that is doing extra testing of a pipeline that goes above a certain limit. So this was a choice by PG&E to avoid two things: a ratcheting down of the MAOP and/or the extra hydro testing that the section would call for. Is that right?

MS. PERALTA: So there was a choice to be made. I wouldn't say that we were in avoidance of anything. It's a practice that we believe to be safe and within the limits of operation allowed by the pipeline.

MR. CLANON: And I didn't mean to use a word that would put you on the spot like avoid, but I still want to understand that the purpose of the policy was, in PG&E's view, that it was necessary to keep the maximum pressure at the former level, that you had to do that or you would have had to do the hydro testing. Is that right?

MS. PERALTA: Not necessarily hydro testing, but do a long seam inspection if we had deemed that manufacturing threat to become unstable.

MR. CLANON: Through some other assessment?

MS. PERALTA: Some other assessment, yes.

MR. CLANON: Thank you.

I've got a series of questions but I'm just going to, in the interest of time, just going to sort of lay out what I'm interested in knowing and have you -- and I think you may still be the right person, Ms. Peralta, or maybe Mr. Daubin as well.

We had some discussion with the Technical Panel about evaluation work that you're doing, especially on the Peninsula lines now, to compare what's under the ground with what's in your records, and I'm aware that the Public Utilities Commission has ordered you to do very significant amounts of that kind of reconciliation. I want to know what information you had before September 9th, just in your day-to-day operations in administering the Integrity Management Program, what were your sources of information about what's under the ground? How did you verify those sources of information? And did you have any program for benchmarking that information, for example, as there are issues that arise in other states, whether you're aware of that and you're able to factor that in?

MS. PERALTA: So there were several questions there. So we use a variety of sources and we integrate them into the Integrity Management Program. One is GIS. We also do use the source job documents and feed them into our program. We are constantly improving and we are, of course, accelerating that improvement in terms of our records research, and as we get more information from the jobs, we will input those into our GIS system to be utilized by the program.

MR. CLANON: And what about benchmarking with other states, with other pipeline operators? Are you in a dialogue or is PG&E in a dialogue with other folks who are operating systems like this, especially now that the infrastructure is aging? It's aging for everybody at more or less the same pace now, and I know that the industry itself is doing a lot of thinking about this. How do you benchmark your activities? And I see that my light is red, so I will stop there and leave it to the Chair to say if I have enough time to hear the answer.

CHAIRMAN HERSMAN: Please respond and then we'll move to the next group.

MR. SALAS: So we have a fairly structured benchmarking program that we've instituted as relates to both gas and electric. We use AGA and other fora to gather data. Having said that, getting asset level data is a little bit more challenging and that's more ad hoc. We will get system performance data and we probably get more robust data at the distribution layer of our system than we do at the transmission layer of the system. So that's an opportunity for improvement.

MR. CLANON: Thank you.

CHAIRMAN HERSMAN: Thank you, Mr. Clanon. PG&E.

MR. JOHNSON: Thank you very much. I have a question for Mr. Lee.

Earlier this morning during the technical discussion, you referenced industry references when talking about automatic and remote control shutoff valves, and you specifically stated that those studies directly impacted and discussed injury and property damage and concluded that the damage was done in the first 30 seconds. Is that correct?

MR. LEE: That's correct.

MR. JOHNSON: Thank you.

Also earlier during that same discussion, you were asked questions about a letter that Rich Arrieta of PG&E sent to the U.S. Department of Transportation in 1999. Do you recall that discussion?

MR. LEE: Yes.

MR. JOHNSON: And that letter was in response to the U.S. Department of Transportation requesting information on a request for comment on rulemaking. Is that correct?

MR. LEE: That's correct.

MR. JOHNSON: To your knowledge, were any federal regulations implemented concerning the response time?

MR. LEE: No.

MR. JOHNSON: Were any federal regulations implemented concerning the use of automatic control valves or remote control valves?

MR. LEE: No.

MR. JOHNSON: Thank you.

Mr. Slibsager, earlier this morning you also mentioned in your conversation references to the ability to impact flow at Milpitas Station and impact flow at Martin Station. Had you utilized those opportunities to reduce flow at both stations, do you have an idea how long it would have taken before the gas flow would have been down to zero at the rupture site?

MR. SLIBSAGER: I do. If the gas control operators had utilized their authority to issue orders to the crew to close the valves at Milpitas, it would have taken several minutes for that to occur as well as another 3 hours for all of the gas inventory, which is essentially pressure in the pipe, to have dissipated.

MR. JOHNSON: Thank you.

Ms. Peralta, you started to discuss two incidents where hydro testing had been utilized on pipelines and that after the use of those hydro tests, there had been failures in those pipelines. Could you elaborate a little bit on your response?

MS. PERALTA: Sure. What I started to say was that there were two incidents on pipelines in other operators' companies that they had both been hydro tested as well as inline inspected using a variety of tools, including a crack tool, which is capable of assessing for seam defects, and they both failed along the long seam. And so while these were liquid events, and I'm not trying to draw the correlation between liquid operations and natural gas because they are uniquely different, what I'm saying is, is that we cannot immediately state that any one test inspection method is the gold standard, be it hydro test or inline inspection. They all have their strengths and limitations.

MR. JOHNSON: Thank you.

And, Mr. Daubin, one question for yourself. You spoke of the use of journal vouchers to determine and populate the GIS information system. Can you clarify the use of how these documents might be used to populate GIS?

MR. DAUBIN: Yes. Specifically with journal vouchers, they are a one singular data point. So they are not to necessarily be ignored, but they should be used in conjunction with the engineering specifications that are in the project folder.

MR. JOHNSON: Thank you. That's all I have, Chairman.

CHAIRMAN HERSMAN: Thank you very much. We'll move to Member Sumwalt.

MR. SUMWALT: Thank you. As I look across the table, we have a senior vice president, a vice president, and we have a couple of managers and we have a supervisor. So who of those would be the most junior in the management chain? Would that be Mr. Kazimirsky? I practiced that name many times, and I still messed it up. My apologies.

MR. KAZIMIRSKY: I guess so.

MR. SUMWALT: I'm sorry. I could not hear you.

MR. KAZIMIRSKY: Yes, I think so.

MR. SUMWALT: So I'm going to ask my questions to you, given that you would probably be the more junior in the management structure. So can you please give an example of management's commitment and emphasis to safety within PG&E?

MR. KAZIMIRSKY: Perhaps the first indication is how they work, how the projects get prioritized every year, and the projects that are based on safety requirements always get the highest priority. That also applies to the scope of work; items related to the scope get the highest priority and get funded first.

MR. SUMWALT: Thank you. In the SCADA system, do you have standard operating procedures that you insist on your people in the SCADA system following?

MR. KAZIMIRSKY: I'm sorry. I'm not sure I understood the question.

MR. SUMWALT: Have you documented exactly how you want people in the SCADA control room to -- have you documented procedures?

MR. KAZIMIRSKY: That is probably a question for Mr. Slibsager. He works in the control room.

MR. SUMWALT: Okay. Please.

MR. SLIBSAGER: Sir, yes, we have a training program that requires our operators to successfully pass in the area of SCADA and we also perform an operator qualification, OQ, on them as required by DOT on an annual basis with refresher and 5-year requalification.

MR. SUMWALT: Thank you.

Do you have people that ever don't pass that requalification program?

MR. SLIBSAGER: I'm aware of one operator that did not pass the program.

MR. SUMWALT: Thank you. I was just trying to get a feel for how rigorous the training and standardization program was. So thank you.

This can be directed towards either of you gentlemen. Does PG&E have a confidential instant reporting system whereby employees can report safety issues that they may be concerned of?

MR. SLIBSAGER: That is correct, sir, we do. And it's also the authority of every employee to stop a job if they think it is unsafe.

MR. SUMWALT: And does anyone have any knowledge of how often these confidential incident reports are filed?

MR. SLIBSAGER: I don't, sir.

MR. SUMWALT: Mr. Salas, do you?

MR. SALAS: We receive summary data from an executive standpoint on a monthly basis that looks at trends. It looks across the entire organization so that we can see within functional units the rates and nature of reports. Personal information is blinded to us. So we don't know who is actually reporting, but we get a sense of the substance, the nature and then any follow-up necessary.

MR. SUMWALT: Thank you. Any feel for the number of reports that you're getting? Is it 1 or 2 a month or is it 100 a month or somewhere in between?

MR. SALAS: The numbers, I would say, and I'm really speaking from my recollection, it's on the order of 50 to 100, and the vast majority are dealing with personnel issues as opposed to operational issues.

MR. SUMWALT: Okay. Thank you. Personnel as opposed to operational, and as opposed to specific safety-related issues; is that true?

MR. SALAS: Yes, sir.

MR. SUMWALT: Thank you.

Mr. Kazimirsky, my apologies again, but if you or anyone who works for you has a safety-related problem, do you have assurance that the issue will be followed up upon by senior management, by somebody within the company?

MR. KAZIMIRSKY: Yes, I do. Like I said, the projects and the work and the specific tasks are always based on safety first.

MR. SUMWALT: Thank you. If an employee makes what I'm going to consider to be an honest mistake that might lead to a bad outcome, what, if any, disciplinary action do you feel that PG&E would take on those employees?

MR. KAZIMIRSKY: It probably depends on the circumstances. If the employee violated any process, any rules that we have in place, then he would probably be disciplined. If the error was strictly a judgment error, then he would probably get some coaching, mentoring.

MR. SUMWALT: Thank you. I'm out of time. So thank you.

MR. SALAS: If I may just expand on that, please?

MR. SUMWALT: Yes, thank you.

MR. SALAS: We operate in an environment with a bargaining unit. So we have two bargaining units and the rules with regard to discipline are defined in the context of those agreements. And so we have processes that we would have to comply with which are positive discipline in nature, and there's a process for that. And we have also a similar process, although not negotiated, for our management or non-bargaining unit employees.

MR. SUMWALT: Thank you very much.

CHAIRMAN HERSMAN: Member Weener.

DR. WEENER: Thank you. We've had several conversations about the database, the GIS database. So this perhaps is a question for Ms. Peralta. Just to clear up my understanding, the integrity management system is based on the GIS database primarily. Is that correct?

MS. PERALTA: It is one of the tools that we use in the program, yes.

DR. WEENER: Okay. Now, obviously, the accident showed that the database material wasn't entirely accurate. So what steps are you taking to improve the integrity of the database?

MS. PERALTA: I'd like to pass that question to Mr. Daubin if I could.

MR. DAUBIN: If you don't mind, I could speak to that a little bit better. We are undergoing an entire GIS validation for our transmission network. We are starting primarily with -- actually, excuse me, we have started with and done the analysis of the 30-inch pre-1962 pipe, done that validation effort. We are undergoing a complete validation of the GIS system for, if I may, class locations 3 and 4, as well as class locations 1 and 2 in high consequence areas. And then we are committed to continuing that effort throughout the entire transmission network.

DR. WEENER: So how are you going about getting data for those sections that you don't have data for?

MR. DAUBIN: Several different ways, one of which is -- and just going through the process, if you don't mind. We are validating all of the information within GIS with the engineering specifications in the project folders, and then we are also using validation digs, radiography in certain areas, and we are doing inline camera inspections on several areas to confirm that data as well.

DR. WEENER: Okay. Thank you.

Let me change subjects here for a moment. There was a lot of discussion this morning about how long it took to get somebody out to close the manually operated valves. And given that you've got a system where you can't simply close a valve without having some repercussions elsewhere in the system, assuming that the two valves that were closed manually, finally, at 7:30 and 7:45, as I recall, if those had been remote valves, then there's the assumption that you could instantaneously have closed those. But how much of the time is really required to do the analysis of what the problem is and then make a decision and then at that point close the valve? So how much time would have been saved had you had remote valves?

MR. SLIBSAGER: I believe it would have been at least 15 minutes. Because when you look at the event timeline, the rupture occurred, I've been told, at 6:11 p.m. The alarm went off in the control room near 6:15, and there were actually actions taken in between time where employees were already moving, but gas control made its callouts just at around 6:32 p.m. So it would have taken that long. If the operators had done their analysis, they could have closed valves remotely at that point.

DR. WEENER: Okay. So that takes an hour to an hour and 15 minutes off with the remote valves. Is that correct?

MR. SLIBSAGER: It appears so.

DR. WEENER: Okay.

CHAIRMAN HERSMAN: Member Weener, what question did you just ask, the final question?

DR. WEENER: It had to do with assuming that instead of the manual valves, remote valves were in place.

CHAIRMAN HERSMAN: Yes. And I think the response was, I just want to make sure, I think you said how much time would have been saved, and I think what the answer you gave was how much time it would have taken --

MR. SLIBSAGER: It would have taken.

CHAIRMAN HERSMAN: -- to close them if they were remote valves. Is that correct?

MR. SLIBSAGER: That is correct.

CHAIRMAN HERSMAN: Okay. So it was 15 minutes to close if they were remote valves?

MR. SLIBSAGER: I would say at minimum 15 minutes before the operator would have issued the order to close the valves, which would have taken another couple of minutes.

CHAIRMAN HERSMAN: To actually sequence to close?

MR. SLIBSAGER: That's correct.

CHAIRMAN HERSMAN: So less than 20 minutes?

MR. SLIBSAGER: Yes.

CHAIRMAN HERSMAN: I just wanted to make sure. You were asking how much time would have been saved, and I think he answered how much time it would have taken overall, correct?

DR. WEENER: Yeah, and that's why I did a little bit of arithmetic at the end to say --

CHAIRMAN HERSMAN: Okay.

DR. WEENER: -- it was about an hour --

CHAIRMAN HERSMAN: Okay.

DR. WEENER: -- that would have been saved.

CHAIRMAN HERSMAN: Great. Thank you.

Member Rosekind.

DR. ROSEKIND: I have one issue that I'd like anyone on the panel to address. If you could discuss -- the UPS lost power, the pressure changed, and if you would describe the troubleshooting process that went on, the decision making, timing, response, outcome? Are there standard troubleshooting protocols in the control room? And give us a sense if there are scenarios that are practiced. So give us a feel for when these things happen, what was going on there within all those different realms.

MR. KAZIMIRSKY: When the crew noticed that the power supplies failed, that we lost power to the pressure transmitters, they first went to the source of the power, which were two 24-volt power supplies. And when they discovered that there was no output from these two power supplies, they went upstream to the circuitry trying to figure out where the failure could have been.

There's no standard procedure for that because troubleshooting is probably one of the most unpredictable activities. But in this case, the troubleshooting involved checking individual components, checking wires, because during the work some of the wiring has been changed. And eventually they did return the power to the power transmitter and the communication came back to life at around 8:40 that night.

DR. ROSEKIND: So let me be more specific then. Are there standardized protocols when power goes out on a UPS system where there's a pressure change of how that's troubleshooted?

MR. KAZIMIRSKY: In this case, it was not the UPS that failed. The UPS was out of service for several months prior to that. Downstream from the UPS we had 24-volt power supplies that fed instrumentation. And while we still had 120-volt power out of the temporary UPSes, the 24-volt output from the power supply is what's been lost that night.

DR. ROSEKIND: And actually I'm less interested in the specifics of this one and understanding your generalized procedures when you have an outage, a pressure change, an outage that happens that's going to ripple through, what are your procedures to respond to that? So is there a standard protocol of troubleshooting? Is there a timeline for that? Do you practice those scenarios? Do you actually sort of look back and determine we need to do that faster, differently, et cetera?

MR. KAZIMIRSKY: Well, we don't practice specific scenarios because I don't think there's any two identical scenarios when something fails in the field. What we do do is we go through the training for our maintenance personnel and the training would normally involve typically troubleshooting steps in case of failures in the system, be it power loss or loss of a specific transmitter or any component of the control system.

DR. ROSEKIND: Anyone else?

MR. SALAS: If I might add, I think we may be talking a little bit past each other. I think Mark is referring to the work activity that was on site by the construction crew. They have a method of procedure and they have a clearance document that identifies step-by-step what they should do to execute the work that they've got to do. To the extent that work in some shape, way or form fails, they have to go into a local troubleshooting sectionalizing process to identify kind of where the issues are.

Having said that, at a broader level, and I think Keith could speak to that, the control room has a different set of protocols as they look at situational awareness and what's going on with regard to the system at large and how they would react to the extent that they have lost control or visibility to a given terminal or station. And, Keith, maybe you can talk a little bit about how you would troubleshoot.

MR. SLIBSAGER: Yes. If our SCADA system were to signal a loss of data at a station or some sort of interruption to the station, the operator has a couple of means they would try first. One, they may try to demand scan or try to reimplement or reinitiate the data communication system. If that's not possible, they would monitor up and downstream of the station to see if anything adverse was happening as a result of losing that data, and if there was, they might be able to, in many cases, back up another station upstream and begin to remotely operate that station to bring the downstream stations back into their normal operation. And also concurrently with that, we would be calling out a maintenance crew to the local area to come out and investigate what had happened and facilitate repairs.

DR. ROSEKIND: And just, last thing, because we're out of time here, but are there exercises that actually sort of run through these scenarios and check responses, response times, appropriate outcomes?

MR. SALAS: There are exercises conducted annually in the local areas in conjunction with gas control on emergency procedures, but we do have telecommunication failures and we are able to go back and post-critique those as they occur throughout the year.

DR. ROSEKIND: Thank you.

CHAIRMAN HERSMAN: Vice Chairman Hart.

MR. HART: Thank you.

I have a question that I'm not sure is appropriate for you, and I'm not sure who else it might be appropriate for, so I'm going to try you first. This is about the pups. I'm just curious about pups. Are they made by taking a full length pipe and cutting it or are they made some other way? And my ultimate question is what do you know about how the pups were made in this particular piece of pipe? And if you're not the appropriate people for the question, I apologize for that. I didn't see anybody else in the lineup to ask that question of.

MR. SALAS: Vice Chairman, I think the more appropriate person would be on the second Panel. Having said that, I can give you a high level answer if you want one right now or we can wait until --

MR. HART: Yes, please. That would be helpful.

MR. SALAS: Just from a policy standpoint, we had as part of our procurement process the ability to, within a purchase order, have a certain proportion of pipe be formed by what were called joiners, and those joiners had specifications that were identified by the utility. So as a manufacturer or mill would be constructing, fabricating, rolling pipe, and doing hydro testing, consistent with the standards that we had specified, as they had failures on those pipes, they had the authority to take sections that were good, that passed, and join them and then use them as filling part of the order. There were limits to how much of that could be a part of any given order, and so that's the way you could get joint sections of pipe into the system.

MR. HART: Okay. Thank you for that and thank you for telling me who else I can ask that of. I appreciate it. Thank you.

CHAIRMAN HERSMAN: Mr. Slibsager, can you tell me how many employees or what types of employees have access to the valves, to the shutoff valves, because not all employees who could be dispatched to the valves might not be able to access them, correct?

MR. SLIBSAGER: Just let me clarify. You are speaking of the manually controlled valves?

CHAIRMAN HERSMAN: Yes.

MR. SLIBSAGER: Yes, you have to be operator qualified and that is in reference to a field employee as well. They've had to have training and prove proficiency to operate and close -- you know, operate a valve open or closed.

CHAIRMAN HERSMAN: And is the access to the valves restricted? Do you need some sort of key or a pass or anything?

MR. SLIBSAGER: Yes, most of these stations are behind cyclone -- minimum behind cyclone fence, with keys on the gates as well as padlocks and chains on the valves as well, the handles of the valves themselves.

CHAIRMAN HERSMAN: Okay. And how many employees would have access to those shutoff valves throughout your system?

MR. SLIBSAGER: I don't know precisely.

CHAIRMAN HERSMAN: Okay. If you all could get --

MR. SLIBSAGER: It's several hundred. I don't know.

CHAIRMAN HERSMAN: Okay. With respect to the shutdown times, are there any standards or regulations or guidance materials that specify minimum response time with respect to shutdown or decision making following a rupture?

MR. SLIBSAGER: I'm not aware of any.

CHAIRMAN HERSMAN: Okay. So, you know, unfortunately in our business, we look at accidents, and seconds sometimes are very precious. In a situation where you're describing it takes 15 minutes to actually determine what next steps need to be taken, when there's a catastrophic rupture like this, I'm trying to understand what are the, you know, minimum expectations? I mean are we going into red alert when they see this happening or is everyone all hands on deck, available, supervisors, you know, jumping to the screens, finding out what happened, or is this just normal practice where they see something like this all the time and it's not going to get anyone very excited?

MR. SLIBSAGER: Ma'am, my gas control operators take these situations very seriously. We have a priority system in our SCADA alarms, and in this case, a low-low alarm or in the case of the high-high alarms that had occurred earlier, they're both the highest priority and require operator action to move forward as quickly as possible. And I have five operators in my control room that are watching these systems.

CHAIRMAN HERSMAN: And so when you get a high-high alarm, is that what you got here, or a low-low?

MR. SLIBSAGER: The high-high alarms were associated with the event that was taking place in Milpitas and low-low at Martin Station.

CHAIRMAN HERSMAN: And when they get alarms like that, are those unusual or are they frequent? Do they see alarms like that every day or is this a weekly or monthly or annual type thing? How often would they see these types of alarms?

MR. SLIBSAGER: They could see them, I would say, frequently. I don't know if it's every day. And they would probably be related to a maintenance activity for potentially a data interruption on our telecommunication system of which they could then easily do diagnostics and determine by looking up and downstream that it was not, in fact, something that was a real pipeline condition, and then they would work with maintenance to do corrections.

CHAIRMAN HERSMAN: So more often than not, they're going to get a false alarm that's going to look like this? They're going to get a high-high or a low-low, and it's actually not going to be a pipeline rupture or leak?

MR. SLIBSAGER: That is possible, yes.

CHAIRMAN HERSMAN: Okay. Just for the general public's, I think, kind of understanding, usually when we think about something failing, if something goes wrong, if something loses power, like a grade crossing, the fail/safe position would be for it to fail down or fail closed. In this situation, we're hearing that when there's a loss of power or an interruption of a signal, the position, the fail/safe position for pipelines is for it to fail open. Can you explain to me why you wouldn't have a fail closed situation with valves when they lose signal or power?

MR. KAZIMIRSKY: We actually have two valves. We have a redundant control. The first valve that fails open is designed that way so we can maintain service to the customers downstream. Had this valve been fail closed, it wouldn't be much different than closing the Milpitas valves as we described earlier. We would lose all customers on the Peninsula in San Francisco. So the first valve fails to the open position. The second valve, however, fails to the closed position. So should the pressure be high or should we lose control signal to the second valve, it would go closed.

MR. SALAS: Madam Chairwoman, if I might add to that? In the gas system, certainly from a local distribution company, a low pressure system, uncontrolled low pressure is as dangerous to the public safety as an overpressure situation. So what we're trying to do is maintain pressure within a tolerance of safety, and what we have are these two forms of control and regulation managing that. So an uncontrolled shutdown can be as hazardous to public safety in many cases as a rupture.

CHAIRMAN HERSMAN: And would an automatic shutdown, an automatic valve, not a remote controlled valve, but an automatic shutdown valve, would that be a dangerous situation for customers?

MR. SALAS: It could be if it didn't have precisely the exact logic controlling it so that it was operating with all of the right inputs and making the right decision. So it will be insufficient just to have, at least in a network system, a valve that works off of simplistic or incomplete insight and information. You really need to have full situational awareness so that you know you're not creating any unintended consequences by shutting down a line.

CHAIRMAN HERSMAN: And prior to the accident, how many ASVs were on PG&E's system, especially Line 132?

MR. SALAS: I don't have that information. I could get that to you.

CHAIRMAN HERSMAN: Okay. Thank you.

Do we have additional questions from the Technical Panel? We'll take 5-minute rounds here.

MR. CHHATRE: Madam Chairman, the Technical Group has some additional questions, if we may have some time.

CHAIRMAN HERSMAN: Sure. Five minutes.

MR. CHHATRE: Okay. Mr. Salas, the PHMSA regulation or the CPUC's regulations are minimum safety standards. Is there a PG&E policy, a written memo of some sort, that says whenever possible for public safety, thou shalt exceed those standards?

MR. SALAS: There's not a standard that specifies thou shalt exceed, although there are cases where we do.

MR. CHHATRE: Do you have a policy or is this a case-by-case basis?

MR. SALAS: It's really an engineering judgment as we define correct course of action or standards for maintenance or other activity.

MR. CHHATRE: Ms. Peralta, you mentioned earlier about two incidents or cases where pipeline ruptured after ILI or hydro tests. Can you please elaborate and be more specific as to which those incidents are?

MS. PERALTA: I was purposely trying not to name the operators prior. But I believe it was Dixie Pipeline as well as Platt, I believe is the operator. But if you have any more questions on that, the second panel could follow up better.

MR. CHHATRE: And those were both liquid pipelines?

MS. PERALTA: Yes, they are.

MR. CHHATRE: How does integrity management address errors in GIS system?

MS. PERALTA: So, in the first steps of the process for, say, inline inspection, all job files are pulled for the creation of what we call our pipeline features list, to see what upgrades may be needed on the pipeline. For the purposes of external corrosion direct assessment, we are specifically focused on those values where we -- those assumed values where we have conservatively assumed a value in the field, and we pull job files according with those values.

MR. CHHATRE: Now, the Integrity Management Program became effective 2004 and your summary sheets still show several items where entries or information is unknown. Can you elaborate why it is taking more than -- so many years, and I won't go into math -- like 6, 7 years, and the values still remain undetermined?

MS. PERALTA: We are constantly trying to improve our systems and our programs and we do this continuously through the Integrity Management Program. For external corrosion direct assessment, we are not pulling a comprehensive set of job packages, and as Mr. Daubin spoke to earlier, we are in the process of comprehensively reviewing our entire GIS system and populating those with source job documents.

MR. CHHATRE: Was that before or after September 9th?

MS. PERALTA: It was after, sir.

MR. CHHATRE: So is it accurate to say that there was no program before September 9th?

MS. PERALTA: No, that would not be accurate. It is part of our integrity management procedures to do so.

MR. CHHATRE: We understand from previous testimony that there was a procedure to send the workers to the accident scene and report and then call 911. Is that policy still in effect?

MR. SALAS: I'm sorry. I didn't quite understand the question.

MS. PERALTA: Can you repeat the question again?

MR. CHHATRE: I'm sorry. This is for Mr. Slibsager. In the previous testimony, it was said that the procedure for responding to emergencies was to send the workers first and then call 911. Does that procedure still exist?

MR. SLIBSAGER: I don't recollect that I said that. I think, if you're speaking of what I had said this morning, I said that it would be proper for and is required for the operators to do the analysis of the system and then start to perform callouts as quickly as possible if that's warranted. My gas control operators do not call 911.

MR. CHHATRE: Okay. Ms. Peralta, the three techniques that you mentioned, one is pressure testing, other is inline inspection, and the third is external corrosion, which has been, I guess, applied to Line 132. Can you please clarify, will the inline inspection identify all defects if there are any in the pipeline segment that you use the tool?

MS. PERALTA: I'm sorry. Can you repeat the question about what inline inspection would find?

MR. CHHATRE: Okay. Inline inspection, when you are conducting inline inspection, will it identify within the detection limit all the flaws that exist in the pipeline?

MS. PERALTA: It depends on what kind of tool you run in that inspection.

MR. CHHATRE: Okay. Now, will your external corrosion direct assessment, will that assure that you have inspected -- that all the flaws in the pipeline have been looked at?

MS. PERALTA: So the assessment methods, and this may be a better topic to explore in the Integrity Management Panel, but the inspection methods are designed to address the threats identified in the pipeline. So they don't look at all threats; they look at the threats identified on the pipeline. And I think this issue is better explored in the Integrity Management Panel.

MR. CHHATRE: Okay. Could the segment which you examine with direct assessment, could a segment next to it, could it have flaws that maybe determine the pipe safety?

MS. PERALTA: I'm sorry. I'm having trouble understanding this line of questioning.

MR. CHHATRE: Okay. The segment of the pipe that you are doing direct assessment of, and you don't see any flaws. My question is could the pipe segments right next to it that you did not look at could have the flaws in it?

MS. PERALTA: So when we perform external corrosion direct assessment, we dig on the most severe signals, if you will. So we are digging where we have any concern. So the logic in terms of external corrosion direct assessment is that anything left in the pipeline is less than what you've directly examined the pipe condition for.

MR. CHHATRE: Okay. Thank you much.

CHAIRMAN HERSMAN: We're going to move on to the Parties. Do any Parties request a second round? PHMSA.

MR. WIESE: Thank you very much. I just have a couple of quick questions if you'll allow.

The first one, because I think several people were asking questions on this, if you'll allow me to touch on emergency response plans. Some people were asking what do your policies, procedures require you to do in regard to contacting local communities, emergency responders. That's how I was taking that line. Does anyone want to say or respond to that maybe in the control room, Keith?

MR. SLIBSAGER: Our control room doesn't have that role, but if a field employee were to request that of my control room, then they could do that, but we don't take it as a primary role.

MR. SALAS: So we have emergency response plans that are designed throughout the service territory and they're managed by our field organizations directly with first responder organizations, and there are protocols for communication and contact.

MR. WIESE: Right. And in the event of an emergency, you have procedures that are based on requirements in California and Federal Code to contact and communicate with emergency responders?

MR. SALAS: Correct. Having said that, another form, another area of improvement that we're undergoing right now is to better integrate all of our emergency response programs to improve the training and exercising with first responders, and we're trying to establish a standard in conjunction with our sister utility in the south of California so that we have one way of managing training, communications and development with all first responders.

MR. WIESE: Great. Thank you.

The last couple of quick questions relate to remote control valves and automatic shutoff valves. I have some background with integrity management myself. And so Mr. Lee did address the notion about a policy and the company's policy as it relates to these valves. The rule also requires you to document through an engineering assessment your decisions about what preventive and mitigative actions to implement. Do you know whether you were doing that as it relates to the valves prior to the failure?

MS. PERALTA: So the memo that Chih-Hung had written is the analysis which is referenced in our risk management procedure.

MR. WIESE: Okay. Great. Thank you.

The last thing, and I was just very interested in the notion that you were doing a benchmark study on remote control valves and ASV installation. Is that something that you as a company, you're going to be willing to make available to the broader community?

MR. SALAS: Absolutely. And, you know, we're working in conjunction with our regulator, with AGA. We've shared information. We've shared information I think at different maybe lower levels within PHMSA. So we're absolutely transparent in that regard.

MR. WIESE: Great. Thanks a lot. That's all I have. Thank you.

CHAIRMAN HERSMAN: Any other Parties requesting additional questions? City of San Bruno.

MS. JACKSON: Thank you. I have to admit to a little bit of confusion about the existing communication plan in place relative to a significant emergency such as we experienced in San Bruno. My question is whether you are considering or whether you can consider designating an employee, such as a district supervisor, for emergency responders to contact in the event of a significant emergency?

MR. SALAS: We're looking at the entire process. We subscribe to the incident command system with regard to management of any significant event. Having said that, we know that we can improve the manner in which we make sure that the incident command on site knows who to go to, who to work with from a utility standpoint, and that's part of the improvement effort that we've employed.

MS. JACKSON: Thank you.

CHAIRMAN HERSMAN: Any other Parties? Vice Chairman Hart.

MR. HART: Just one question related to the Chairman's previous question about high-high and low-low alarms. It's pretty obvious why a high alarm would be potentially hazardous, but it's not so intuitive to me why a low alarm might be hazardous. Would you explain that?

MR. SLIBSAGER: I can. A low pressure situation in our gas system is as important and may be as significant a safety concern as a high pressure, overpressure system. Low pressure in a system may allow us to go into an uncontrolled shutdown, and if we have low pressure that allows the pilot lights in a house to extinguish, then you have the potential for, if gas were to reenter that house through migration of this low pressure around the system before its all evacuated out of the pipe, the gas could intrude back into the house and create an explosive situation.

MR. HART: Okay. Thank you.

CHAIRMAN HERSMAN: Member Sumwalt.

MR. SUMWALT: Thank you. Mr. Salas, I'd like to follow up to a question that I think the CPUC asked earlier, and that is, is the gas industry as a whole doing enough to share best practices with respect to safety-related issues?

MR. SALAS: Thank you, Member. I think a lot happens. We do share information and I think it is, from where I sit, very -- it's a little bit ad hoc. We come together with regard to industry associations. We share data and information when we have very significant, large events such as this horrible tragedy. I would say we could make improvements. We're not quite at what I would call the IMPO level from a nuclear industry standpoint where we are sharing detailed failure or near miss information across the board so that we treat, you know, a failure in Iowa as seriously as a failure in California, and that we all learn from every incident. So I think that's an area that we could collectively improve in.

MR. SUMWALT: Thank you. I know on day 3 we'll be talking about industrywide technology, and it's my hope that we can also ask questions, the same types of questions to the industry organizations, not necessarily related to technology, but with respect to sharing of best practices.

Madam Chairman, no further questions.

CHAIRMAN HERSMAN: Have you all done an analysis of what damage occurred in the first 30 seconds after this release?

MR. SALAS: No, ma'am, we have not. We are relying on the NTSB investigation. We'll contribute any and all information but I've not seen such an analysis.

CHAIRMAN HERSMAN: Okay. And when we go back and talk about the readings that occurred initially -- Mr. Kazimirsky and Mr. Slibsager, maybe you can help me with this. There was a discussion earlier of SCADA losing signal and power interruption and that there was a 500 psi reading, and you mentioned that that was unreliable, that 500 psi reading, because some of the connections had been changed or moved around. So my question to you is how do you know that that reading was unreliable and that the other readings were reliable?

MR. KAZIMIRSKY: At that point we considered all readings unreliable. This particular one or the one that was reading, I believe, over 600 pounds was simply unrealistic because there was no pressure coming in at that value.

CHAIRMAN HERSMAN: Have you ever seen a reading of 500 psi?

MR. KAZIMIRSKY: On the discharge part? I don't believe so because we never exceeded MAOP on the discharge.

CHAIRMAN HERSMAN: So systemwide, you've never seen a reading of --

MR. KAZIMIRSKY: Oh, systemwide, yes, we have. I thought you were referring to Milpitas.

CHAIRMAN HERSMAN: Okay. So how do we know that you didn't exceed 386? How can we know with confidence that that wasn't exceeded if other readings are unreliable at that time?

MR. SLIBSAGER: We earlier showed a slide that showed the large amount of data that exists from the SCADA perspective downstream of Milpitas station towards the San Francisco Peninsula, and there is a site that's within a very close distance, several miles, I mean, less than -- I believe less than 5 miles, and it didn't register that sort of pressure. It exceeded no pressure higher than -- all pressures below 400 pounds on that sensing point. So clearly that 500-pound pressure signal did not occur and transfer down the pipeline.

CHAIRMAN HERSMAN: The last question I have is, as you're evaluating RCVs and ASVs now post-accident, what guidance or information do you have about how you would install those or how you would prioritize them?

MR. SALAS: Madam Chair, we haven't concluded all of the protocols and the decision trees and I would say they're fairly mature, but they're not complete yet, and we're looking to vet them with industry experts kind of nationwide. Having said that, we know we want to focus on HCA geography. We know we need to do significant upgrade with regard to control logic so that the people in the control room floors can manage many, many more streams of data intelligently. We can't have them just look at more alarms. We need to have tools that help parse and interpret those alarms so that good action is taken. So we have work in a number of areas, but the real focus is going to be in high consequence areas where we've got population and to give us more visibility inside of control with regard to our system.

CHAIRMAN HERSMAN: Do you think the industry needs minimum requirements for ASVs or RCVs?

MR. SALAS: I think there's probably value in a more standard approach than in a thousand different approaches.

CHAIRMAN HERSMAN: Okay. Thank you very much. I thank the Technical Panel, thank the Parties, and thank all of the witnesses on this first panel. It was very helpful and we appreciate your response to our questions.

We're going to take a recess, and we will reconvene at 2:20.

(Off the record.)

(On the record.)

CHAIRMAN HERSMAN: If everyone could take their seats, we're going to reconvene and begin with the second panel.

Ms. Ward, would you please call the witnesses?

HEARING OFFICER WARD: Thank you, Madam Chairman. The witnesses are already seated. If I could have Mr. Dauby and Mr. Fassett to please stand? Please raise your right hand.

(Witnesses sworn.)

HEARING OFFICER WARD: Thank you. Please be seated.

Mr. Dauby, if you could please state your full name, your title and your current duties and responsibilities?

MR. DAUBY: Certainly. My name is Frank Dauby. I'm a supervising engineer in the Integrity Management Group at PG&E. I've been employed by PG&E for 27 years in a variety of gas engineering positions. For the last 7 years, I've been supervisor for the ILI group and for the last year, also including external corrosion direct assessment. And I hold a bachelor's degree of civil engineering from Georgia Tech.

HEARING OFFICER WARD: And, Mr. Fassett.

MR. FASSETT: Yes, I'm Bob Fassett, Director of Integrity Management and Technical Support for PG&E. I've been employed by the company since June of 1990. I've had a variety of engineering responsibilities from the engineering level as well as supervision level. I've also had a number of construction level responsibilities as well. In general, my responsibilities as Integrity Management director is responsibilities for the Integrity Management Programs as well as the maintenance processes associated with pipelines.

I'm also the chairman of the National Association of Corrosion Engineers' standard on external corrosion direct assessment. I am a member of that same society, NACE, for the steering committee for pipeline integrity, and I am the third chair on the American Gas Association's distribution, construction and maintenance committee.

HEARING OFFICER WARD: Thank you. And for the record, we have Mr. Salas, who is going to join us on this panel, and he's already been sworn in and qualified.

Madam Chairman, all three witnesses are now sworn in and qualified and ready for Mr. Gunther for questioning.

CHAIRMAN HERSMAN: Thank you very much, and I'd also like to recognize Chris Johns who is the president of PG&E who has been with us all day in the audience, and we have a day full of PG&E witnesses. So thank you for being here to support them.

Mr. Gunther, go ahead and begin your questioning.

MR. GUNTHER: Thank you, Madam Chairman.

Mr. Dauby, what methods are the most appropriate to detect flaws of the type found at the fracture origin on Line 132?

MR. DAUBY: There are several methods that are capable of assessing long seams, one of which is hydro tests and another one which would be specialized inline inspection tools, generically known as crack tools.

MR. GUNTHER: Which of these methods would also apply to manufacturing and fabrication defects?

MR. DAUBY: Either technology could be utilized for addressing manufacturing. Seam flaws would be one type of manufacturing threat.

MR. GUNTHER: How much of PG&E's pre-1970 transmission pipelines are capable of being inspected by inline inspection tools?

MR. DAUBY: I don't have an exact mileage figure for that. I can tell you, in general, PG&E's gas transmission system was not built with piggability in mind prior to the mid 1990s, when rules went into effect requiring that all new pipelines built be made piggable. And thus, anytime we implement an inline inspection project it requires a 3 to 4-year process to engineer upgrades, to replace major components on the system, including mainline valves, fittings, T's, certain types of drips, et cetera, just to be able to get the line ready for inline inspection, and then actually to perform the cleaning and inspection and then post-assessment and repair.

MR. GUNTHER: Is PG&E taking action to make more of these transmission lines capable of being evaluated by inline inspections? Still Mr. Dauby.

MR. DAUBY: Yes, we are. We've had plans in place for some time to continue to upgrade various sections of our pipeline systems to make them capable of running inline inspection tools that definitely predates the incident in San Bruno, and we will continue to upgrade pipelines such that we have an option of running either inline inspection tools or potentially doing ECDA or hydro tests. But at least if they're upgraded, we have the option of running those kinds of tools.

MR. GUNTHER: And again, in the case of Line 132, was this done before September 9th?

MR. DAUBY: Yes, we had a plan in place to proceed with the engineering and the upgrade of Line 132 back in 2008, after tools became available in the industry that would allow negotiation of the various pipeline diameters that exist in that pipeline.

MR. GUNTHER: Has PG&E conducted another method of pressure testing on Line 132?

MR. DAUBY: I'm sorry. Another method?

MR. GUNTHER: Or any method of pressure testing?

MR. DAUBY: That I'm aware of, outside of any new construction that's occurred on the pipeline since pressure testing became required in 1970, I'm not aware of any specific sections that we've utilized hydro test as an assessment method.

MR. GUNTHER: Okay. Mr. Fassett, what measures have been applied to Line 132 to address manufacturing and/or fabrication defects?

MR. FASSETT: As described by Ms. Peralta this morning, the manufacturing defects were defined in the Code as pre-1970 ERW or joint efficiencies of less than 1. Based on the metallurgical report, this type of seam, submerged arc welded seam, would have a joint efficiency of 1 and therefore would not be considered to be a manufacturing threat.

MR. GUNTHER: But again, under the Integrity Management Program, can you really -- I'm not sure you answered the question. Again, what measures have been applied to Line 132 to address manufacturing or fabrication defects?

MR. FASSETT: So relative to that definition, the analysis was done on 132 as part of the development of the baseline assessment plan. There was no triggering of the items that would make it considered to be an unstable manufacturing threat for some of the segments. Segment 180 was not one of those segments. There were no triggering of that. By that I mean there's no record of a leak on a long seam or that the maximum operating pressure had been exceeded.

MR. GUNTHER: Okay. Could you explain why if inline inspection was not feasible, why didn't PG&E conduct pressure tests on line 132?

MR. FASSETT: The manufacturing threat had not been considered to be unstable. When a manufacturing threat is not unstable, then you have the full gambit of tools: the direct assessment, inline inspection, or hydro test tools available to you.

MR. GUNTHER: So basically, then, if a manufacturing defect then is -- you decide whether it's stable or not. And then if it's unstable, you act on it; and if it's stable, in essence, you leave it alone. Is that what you're saying?

MR. FASSETT: No, I'm saying you have the full gambit of tools. If I may, I could explain the positives and negatives associated with each of the three tools.

MR. GUNTHER: Go ahead.

MR. FASSETT: As discussed earlier, you have the option of hydro testing, inline inspection, or direct assessment. They are tools that are compatible with each other, but they do different things and they tell you different things.

A hydro test requires putting water into your pipeline, and on vintage pipelines, that's a concern because if the pipe isn't piggable, we're concerned that getting the water out would be difficult, and even with modern day driers, it's not 100 percent dry. So you would leave water behind, and the reason you leave water behind is the changing diameters, the partially blocking valves, that Mr. Dauby alluded to. As that poly pig goes through it -- and the pig is basically a very stiff rubber-coated sponge shaped like a cylinder. As it tries to negotiate its way around those pinch points, you expect water to be left behind. We don't like leaving water behind. That's a concern for internal corrosion. It's also a serious impact to our customers to take them out. So unless we have to assess that way, hydro test is not the tool used.

ILI, again as Mr. Dauby stated, you have many -- these vintage pipelines have issues associated with them. ILI would be a step up from hydro test, for example, because the hydro test when you pass the test, all it tells you is you passed the test. It doesn't tell you that you may have some corrosion cells, for example, that were small enough to not be failed by the hydro test but still in your pipeline. An ILI would tell you that you still have flaws you need to go look at and where to look at them.

And DA also does that, whether it's the direct assessment for internal corrosion, stress corrosion cracking or external corrosion, the whole design behind them is to find out where you have areas that need more attention and give you the opportunity to actually go excavate them and mitigate them.

MR. GUNTHER: Okay. The PG&E Integrity Management Plan addressed risk factors. How are those risk factors identified and what are they?

MR. FASSETT: Was that to me?

MR. GUNTHER: Yes.

MR. FASSETT: The Integrity Management Program includes a list of 22 threats associated with the pipeline. Those are broken down into nine categories which are further broken down into three levels. The three levels would be: time dependent, stable and time independent. Do you want me to go into the specific areas?

MR. GUNTHER: That's okay. Is population a risk factor?

MR. FASSETT: So the Integrity Management Program is based on high consequence areas, and high consequence areas are calculated as discussed earlier in a couple of different ways, but it is relative to population. Essentially high consequence area is an area of high density around the pipeline or an area around the pipeline where, although it may not be an urban area where we would see higher densities, it would be areas that would require more difficulty in evacuating the structures, such as a hospital, a church, senior citizens home, and that kind of thing.

MR. GUNTHER: Okay. As a risk factor, how severe or great would a population, at least under the Integrity Management Plan, be?

MR. FASSETT: I don't understand the question. I'm sorry.

MR. GUNTHER: Okay. As the Integrity Management Plan ranks the risk factors, as more severe or less severe, where would population fall on that list?

MR. FASSETT: If I may, could I step back a little bit and explain the equation we use? A simple --

MR. GUNTHER: If you can be brief.

MR. FASSETT: So risk as we understand it in the industry, we all use a relative risk ranking, which is the likelihood that a threat should cause a problem times the consequence. That's what risk is. And when we're told what an HCA is, what a high consequence area is, that means high consequence or consequence has already been defined, and really the only thing we're addressing is the likelihood portion of that equation. So when we calculate the risk it's for, as Ms. Peralta mentioned earlier today, it's for the establishment of the scheduling of the work.

So the program requires us to determine what's high risk and that that has to be done in the first 5 years of the baseline assessment plan, and then the rest of it can be done in the second 5 years. The program was started by law, December 17th, 2002, and we're required to have that first assessment completed by December 17th of 2012. But that's just the first go through and then there's a continuous evaluation that takes place at least 7 years after the evaluation of each line. You may have to do it sooner, depending on what was discovered in the assessment and the mitigation taken.

MR. SALAS: If I could add, just maybe to expand a little bit. Consequence is really driven by three considerations: impact on population, impact on the environment, and impact on reliability. By far and away, the heaviest weighted component is the impact on population of that consequence of failure calculation. So population bears heavily on the value.

MR. GUNTHER: Thank you for that explanation.

Mr. Fassett, could you please describe the rationale for assigning risk?

MR. FASSETT: The rationale for assigning risk relative to the Integrity Management Program --

MR. GUNTHER: Yes.

MR. FASSETT: -- is so that we understand the ranking of the prioritization. We are required to determine what is high risk on our system and that needs to be completed in the first 5 years of the baseline assessment plan.

MR. GUNTHER: And how are these risks quantified?

MR. FASSETT: There is an analog equation that was spoken of earlier this morning that uses different categories such as third-party damage, corrosion, outside force, those types of things. There are committees of subject matter experts that meet to put the weighting on them to establish that equation and also to incorporate things that have come up through attendance in conferences or papers from DOT, that kind of thing.

MR. GUNTHER: PG&E's required to conduct self-assessment of its Integrity Management Plan in accordance with Section 12 of ASME, American Society of Mechanical Engineers, American National Standards Institute B31.8S. Please explain how PG&E complies with that standard.

MR. FASSETT: In various ways. We have third-party consultants that come in and will audit portions -- small portions or large portions, depending on the issues at hand. We also have built into the processes -- for example, with direct assessment, there's specific effectiveness analysis requirements that are required of that policy. There's validation digs, both on the inline inspection side as well as the direct assessment side, that requires us to -- essentially you come up initially with your hypothesis or your evaluation of where you think your concerns are, you go excavate them, you validate that, and then you go excavate some other areas that you don't think you have concerns with, and you make sure that what you see in the ground is what you expected to see based on your analysis.

MR. GUNTHER: Could you please provide details with respect to the elements and processes of the PG&E Integrity Management Plan quality assurance program?

MR. FASSETT: In short, it's all those things I just stated. I'm not sure, is there some specific area that you --

MR. GUNTHER: In other words, then you don't want to add to what you had stated before with respect to the, you know, quality assurance program?

MR. FASSETT: I understood it that I answered that as part of assessment, and maybe I don't understand the question, but in my mind, the assessment of the effectiveness is the same as quality assurance processes, but I'm sorry if that --

MR. GUNTHER: Oh, okay. Yeah. Could you please describe the process of self-assessment?

MR. FASSETT: There are various ways of assessing individual procedures and ways of assessing what we call the Risk Management Procedure Number 6, which is the overarching procedure for how we will manage the program. That particular one has been audited by third-party experts. All of our procedures following San Bruno have been -- now in the process of third-party consultants reviewing all the procedures, evaluating relative to Code, evaluating relative to industry consensus, and we'll also be making recommendations that go beyond either Code or industry consensus.

MR. GUNTHER: And this is since September 9th?

MR. FASSETT: That particular program is since September 9th, but the other efforts were -- with the third-party review of RMP6 was done prior to September 9th.

MR. GUNTHER: And how does PG&E ensure the quality and effectiveness of its Integrity Management Program?

MR. FASSETT: In many ways, which I believe I've explained. Is there a specific area? I don't think I'm tracking. I'm sorry.

MR. GUNTHER: What means are there for PG&E to make adjustments and improvements to the quality management program?

MR. FASSETT: In review of the procedures. The technical teams, they get together. They review not just the weighting, but they also review the procedure. If there's no changes that need to be made, they won't necessarily meet. But that's done by subject matter experts. It's done -- there's a monthly meeting of the team where issues are brought up, where schedules are brought up, concerns that are brought up. That's an opportunity for them to share amongst themselves things that perhaps they may have learned from recent announcements from the DOT, conferences that they attend as part of their continuous education in this field, those kinds of things.

MR. GUNTHER: Who within PG&E evaluates the assessments of the Integrity Management Plan?

MR. FASSETT: That's done by the team, by the subject matter expert technical teams, and periodically it's done by third-party experts.

MR. GUNTHER: And who reviews and approves the findings of these assessments?

MR. FASSETT: That depends on what the changes are to the procedures. Changes to RMP6 are reviewed essentially from the supervisor to manager to director then to vice president level.

MR. GUNTHER: I was going to say, in that case, can you just tell me what the minimum level of approval is and what the maximum level of approval is?

MR. FASSETT: RMP6, because it's the overarching document, would be the maximum. That would go to the vice president of gas transmission and distribution. The risk management instructions, which are more detailed on specific levels associated with tasks within the integrity management team, those could be approved at the supervisor's level. And the risk management procedures outside of RMP6 could be approved at the manager's level.

MR. TRAINOR: Mr. Dauby, is it?

MR. DAUBY: Dauby, sir.

MR. TRAINOR: Dauby, pardon me. I just wanted to follow up on a few of the questions that Mr. Gunther asked you.

You mentioned the types of inspections and tests that are able to detect a flaw of the type that caused the fracture of Line 132 on September 9th. You mentioned the hydro test, inline inspection and with respect to inline inspection, you mentioned a crack tool. Between you and Mr. Fassett, you've also described the challenges of doing a hydro test on Line 132 and the limitations you have in conducting inline inspections on Line 132. That being the case, what other avenues are open to you to detect and eliminate flaws of the type that caused the facture or led to the facture of this pipeline?

MR. DAUBY: Well, one of the options that we are in the process of pursuing and have pursued to validate that there's an inside weld on the pipe is to actually open up the pipe and then do a camera survey to validate that the pipe is actually welded on the inside if it was purchased to be double submerged arc welded pipe. In regards to the different types of crack tools, those do exist and could be employed in certain situations around the transmission system. One of the big limitations on those with the present technology is that they can only inspect one diameter at a time, and thus depending on how much footage you have at a single diameter, that limits the length of inspection you can do in one inspection.

MR. TRAINOR: With respect to running a camera through the line, again what limitations would that present to you? I mean, you mentioned that it would detect whether there was an inside weld, but beyond that, would it have the resolution to pick up other types of defects like cracks or perhaps dents or anything of that nature?

MR. DAUBY: No, sir. The camera inspection is basically just a visual, you know, the opportunity to visually inspect the inside to confirm that there actually is a weld on the inside of the pipeline. But outside of any very significant defects, it would not provide detailed information regarding cracks.

MR. FASSETT: If I may add, sir?

MR. TRAINOR: Please.

MR. FASSETT: One of the categories I left off was other technology besides hydro test, ILI, and direct assessment. The camera that we're using was not considered in that group, but it was the quickest way we could access the pipe to look for what we believe was the flaw that failed this line. We have been working with NYSEARCH and other members of industry for the past 5 years on the development of a self-propelled inline inspection tool, basically a robot. We've taken that robot and we're working with NYSEARCH and with their developer to modify it into a self-propelled camera that could go into a system with pressure on it, and to add high resolution cameras to it.

The technology that was just recently supported or released was a product called Explorer II and that was supported also through the Department of Transportation, PHMSA organizations, supported that development. These are instruments that the camera alone, besides being able to identify whether you have a long seam that's missing a weld, what we found when we did the investigation as part of this NTSB investigation --

MR. TRAINOR: I think we're getting off on a tangent here.

MR. FASSETT: I'm sorry.

MR. TRAINOR: These high resolution cameras, before we leave them, as I understand your statement, they're in the process of being developed but not currently available or widely in use. Is that a fair statement?

MR. FASSETT: The tethered type is available and widely in use currently. The swimming type or the self-propelled type, we believe we'll have one by May. That could be used on this project.

The one thing I wanted to add quickly, I'm sorry, is what we found by using the cameras, we found labeling on the inside of the pipe which we understand has come from the mill. They would label it in a specific sequence associated with the American Petroleum Institute standard for labeling.

MR. TRAINOR: Right.

MR. FASSETT: And by collecting that, we learn more and more about where the pipe --

MR. TRAINOR: All right. I appreciate the efforts there but --

MR. FASSETT: Sorry.

MR. TRAINOR: -- I have limited time here and number of questions to ask.

Mr. Dauby, you also mentioned there's a plan to replace mainline valves to make the lines more piggable. Is there any projected date by which your older transmission lines, like 132, would be piggable?

MR. DAUBY: For 132 specifically, we're proceeding with engineering this year, in 2011, and we propose to inspect it by 2014. We have a number of other projects that are both in that time frame as well as going on out into the future. As I indicated earlier, our system was simply not built piggable and inline inspection really isn't practical in a lot of our pipeline system.

MR. SALAS: If I could add?

MR. TRAINOR: Certainly.

MR. SALAS: We're currently developing a submittal to our regulator which will allow us to propose a much more aggressive modernization of our pipeline than we've been undergoing to date. We have been upgrading our pipe progressively to be more piggable. We want to take a much more aggressive stance and so we're going to propose projects to be able to do that in much shorter order.

MR. TRAINOR: And are you looking to do all of your transmission lines, Mr. Salas?

MR. SALAS: Ultimately, yes, the priority being HCA.

MR. TRAINOR: Mr. Fassett, Mr. Gunther asked you to identify the types of manufacturing or fabrication defects. What were the mechanical or fabrication threats to Line 132 under the Integrity Management Plan?

MR. FASSETT: Some of the pipeline segments, not Segment 180 -- let me back up a little bit. This pipe varies in diameter across the length. So some of the pipeline is pre-1970, electric resistant welded, low frequency pipe, and some of it has a joint efficiency of less than 1.

MR. TRAINOR: What consideration was given to perhaps defects that might have been in the pipe or as a result of manufacture or fabrication that might develop over time and reach a critical size and fail? How did you address those types of conditions?

MR. FASSETT: Of the 3 major categories that those 22 threats I mentioned earlier fall under, there is time dependent, which is categorized as internal, external or stress corrosion cracking. And under stable, there's several, but one of them is manufacturing defects. If the defect is considered to be stable, it is not expected to grow over the expected life of the pipeline to failure. This particular flaw is something that -- I've been in this business for a couple of decades. I never would have expected to see a DSAW long seam, not just missing a weld on a 4-foot can, but the two 4-foot cans next to it. Since the metallurgical report has come out, I've had colleagues from all across the industry who have my experience and, in some cases, twice as much time, that were equally surprised to see this.

MR. TRAINOR: Well, let me approach this another way here. You mentioned time independent threats and --

MR. FASSETT: Time independent, yes, sir.

MR. TRAINOR: And external corrosion damage assessment is one technique. Internal corrosion damage is one technique. And I know that in the testimony on the previous panel, these direct assessment methods were being mentioned as being applied to Line 132. My question is how would those particular techniques detect the kind of flaw or defect that led to the fracture of this pipe?

MR. FASSETT: Respectfully, to clarify, the time dependent threats that we look at in industry are external corrosion, internal corrosion and stress corrosion cracking because they grow over time. Corrosion cells get bigger. Stress corrosion crack colonies get larger.

Manufacturing threats is categorized typically under stable, unless you know something that would make them unstable, at which point direct assessment would not be the methodology we would use. We have experience with a pipeline up north where this was the situation and we've used a crack tool to inspect that pipeline.

MR. TRAINOR: One more question along these lines. This pipeline, this particular segment of the pipeline, was installed, constructed in 1956. As the pipeline ages and any internal manufacturing fabrication defects may over time begin to go from being stable to unstable -- we've seen it in other types of pipeline failures. I'm not saying we characterize it in this way for this particular accident, but I would think a pipeline operator would have to be mindful of the possibility. So that's what I really want to ask you to address. How is PG&E mindful or attentive to the fact that there may be manufacturing or fabrication defects that may in time become unstable?

MR. FASSETT: So the way that's defined is if we've had a leak on a long seam -- specifically the guidelines or the guidance on that is that if there's a leak on a long seam and it's select seam corrosion, we would call that something that needs to be inspected for the manufacturing threat. If we have a leak on a long seam, regardless of what caused it, we would say that that has a manufacturing threat; therefore, we would not use direct assessment on it. That was the case of the example I used up north. Also, industry uses that if you've exceeded the 5-year MOP on the segment, then one needs to look at that as an unstable threat, and in this situation, as mentioned earlier, that didn't happen.

MR. TRAINOR: All right. Let's move forward here.

MR. FASSETT: But if I may add quickly?

MR. TRAINOR: Oh, sure.

MR. FASSETT: I'm sorry. This is an area that, especially from the surprise of what we saw with what we believe may have failed this pipeline, that the concept of manufacturing of vintage pipes, what we know about them, what were their processes. 1948 was when we believe this pipe was created. That was when the technology was invented also. We think we need to look further into those vintage processes, the quality control changes that have taken place over time, and get a better understanding of why these fail and what we can do to prevent them.

MR. TRAINOR: You talked about third-party consultants doing audits of your Integrity Management Program. When was the last such audit done?

MR. FASSETT: There was one, I believe, in 2007. And then in 2009, we -- it wasn't an audit, necessarily. We had asked a risk management expert to come in and look at what we would need to do to move from the current relative risk evaluation equations that we use, as many in industry do, to a probabilistic methodology that Mr. Salas referred to earlier.

MR. TRAINOR: Were there any other findings of this consultant with the audit?

MR. FASSETT: I'm sorry. Which one?

MR. TRAINOR: Were there any other findings as a result of this audit?

MR. FASSETT: The 2007 audit, as I recall, there was recommendations in various areas that affected the direct assessment procedure, the ILI procedure, and the risk management procedure. Those teams took that information and within a few months of receiving it, made the changes to the procedures.

MR. TRAINOR: Thank you, Mr. Fassett. I'd like to use the remaining time to address questions to you, Mr. Salas. As you know, with the implementation of integrity management as a pipeline safety philosophy, it's been our view that the success of this type of plan is dependent upon the self-assessments conducted by the operator of their Integrity Management Program. So I'd like to get your input on how PG&E specifically conducts self-assessment on the effectiveness of its Integrity Management Program.

MR. SALAS: Mr. Trainor, what I would do would be to reiterate what Mr. Fassett had said earlier. But at a broader level, where I would be interested and I think the leadership organization, in terms of are we meeting the program objectives as it relates to execution. So we have, as defined by the objectives with regard to integrity management, the need to complete the first lap, as it were, of assessment by December 17, 2012. So one of the ways we look at the effectiveness of the program is, are we advancing the program? Are we making the right kind of analyses with regard to what we find as we do assessments? When we identify anomalies, are we taking action, corrective action?

We are relying on input from our regulator that comes and audits us or looks at the quality of our program, third parties looking at our program. Are we acting on the findings that they identify? As we improve the program -- we recognize that this was something that was new and introduced to the industry in 2004, and so we expect the process to be one of continuous improvement. So we look at it from a variety of vectors to assess the effectiveness of it.

Obviously, we're looking to manage a risk profile over time down. And I think one of the issues that we see with a relativistic model set is that -- you know, we're self-assessing, so, you know, we want a more objective view as we look at ourselves, and we think a probabilistic transition will offer us that.

MR. TRAINOR: What types of checks and balances are there within PG&E to ensure that your self-assessments are comprehensive, they're objective and that follow-up on them is being executed?

MR. SALAS: I rely on the management team to be looking at performance. We have monthly performance meetings as relates to pipeline performance, to the manner in which we're scheduling work, be it for corrective or safety-related programs connected with the Integrity Management Program. So we're watching to make sure that we're hitting the targets that we've got with regard to corrective actions. It's really a dynamic process that we look at as well as the more periodic formal reports that would come through.

MR. TRAINOR: What level of management is involved in the monthly assessments?

MR. SALAS: Senior vice president, vice president, senior directors and directors.

MR. TRAINOR: So you as a senior vice president would be participating in this process?

MR. SALAS: Correct. I have a colleague that's responsible for maintenance and construction in all our field forces. She also participates.

MR. TRAINOR: Okay. I guess I would just ask the panel, what aspects of your Integrity Management Program, perhaps we have not specifically mentioned today, do you think is relevant to this accident?

MR. SALAS: Well, given, quite frankly, the tragedy and the huge loss, I think we need to stand back and question ourselves, you know, from the beginning. And I think that's our intent with regard to integrity management as well as the risk management protocols is to challenge any and everything that we've done to see what we could do differently, what we could do better, what we could discover as a result of the root cause findings of this particular tragedy, and incorporate those findings into the ongoing program so we can absolutely, positively prevent a similar occurrence in the future.

And I think that's why the reference to DSAW is so critical so us. To the extent the findings of this investigation conclude that there is an issue in an area that we didn't see a threat prior, tells me that we need to step back and relook from the beginning how we are assessing in some categories.

MR. TRAINOR: And could you summarize the specific actions that PG&E has taken in this regard since the September 9th accident?

MR. SALAS: We've engaged Gulf Engineering, EN Engineering and other experts to relook and opine on our entire program from kind of a soup to nuts basis, and to propose any and all changes that they see as being fit for us to consider for improvement.

MR. TRAINOR: I believe Mr. Chhatre has one question for the panel. This concludes my questions.

MR. CHHATRE: Mr. Fassett, how does ILI or direct assessment, be it internal, be it external, can identify the defects in materials, meaning the material being A grade or X52 or X42?

MR. FASSETT: I'm not sure I understand the question. Are you asking is there an analysis done on the --

MR. CHHATRE: No. What I'm asking is, if I have X42 listed as the material for my particular pipe segment and the material turns out to be type B or Class B, how would any of these inline inspections or direct assessments, will point out to that discrepancy?

MR. FASSETT: None of the three assessment tools allowed through the program would tell grade of the pipe. There are recently efforts through GTI, the Gas Technical Institute, and others to develop in-the-field or in-the-ditch technologies for looking at chemistries. And it's not quite approved by ASME yet, but there's an ability to evaluate the yield strength of the pipe without having to do destructive testing.

MR. CHHATRE: Now, looking at the sheets, the survey sheets, there are -- again, like I asked that question earlier, with almost 7 years in integrity management, we still see some areas where the information is not available. What action the integrity management department has taken to resolve those and is there a deadline to completely eliminate all those unknowns?

MR. FASSETT: As it relates to the Integrity Management Program, as Ms. Peralta mentioned earlier this morning, as each project is performed, records are researched and evaluated, and those records, in the case of direct assessment that don't have what we call assumed values, they're conservatively assumed values and accepted through the industry based on support. Those values that are assumed, we do a record search to evaluate them. That's one method. The other method is we have a rather extensive inspection form that when we do excavate the pipelines, we compare what we believe we're seeing, and that's an area that we continue to work on.

Prior to September 9th, we had sent, I believe, all of our direct assessment data from all phases, the indirect inspection phase, the tool phase, as well as the direct examination phase, was sent to DOT PHMSA as part of a program that they were developing specifically for addressing casing DA as well as learning more about how to get better at ECDA.

MR. CHHATRE: Okay. DSAW was mentioned earlier by both you and Mr. Salas, and my question is, since we did not even know that the pups existed at the rupture location, the lab report shows that the pups are of different materials and different mechanical properties. How do you even know that pipes were DSAW and that DSAW is a problem?

MR. FASSETT: The body of the pipe didn't fail. The metallurgical report states that the origin of the failure started in the seam. As mentioned earlier, we have reduced this to either of three purchase orders that were made from one mill from 1948 to 1953. One of those purchase orders we provided a Moody

Engineering report that explains that the specification for the pipe was to be 3/8 X52, and that the design of the seam was at that time what they would call electric weld, where they define that further to be the weld of the long seam from weld from the outside to penetrate 2/3 of the wall thickness and the weld from the inside to penetrate 2/3 of the wall thickness. The fracture fractographs or the graphic cross-section of that long seam that failed, shows a weld penetration of approximately 2/3 of the weld seam -- of the thickness, rather. It did not line up directly on the seam, so only about 50 percent of that penetration was actually binding them together. But there were segments, as I believe you mentioned or showed in your presentation, where it did get both the outside and inside weld, which is what leads us to believe that its an issue with DSAW manufacturing of a vintage nature. Because I would like to add that the quality control for the manufacturing of pipe has changed greatly since 1948, leading up to in 1963, where the American Petroleum Institute requires 100 percent radiological inspection of the long seam specifically for DSAW pipe.

MR. CHHATRE: Do we even know that these pups were manufactured and came from a certain supplier since we even do not know they're of minimum standards? According to PG&E, they're less than 5 feet. I mean, do we have a certain extent of confidence that these pups actually came from a regularly double submerged arc welded pipe?

MR. FASSETT: Specifically, unfortunately, there are not on a regular basis identification placed on the pipe at the mill on short lengths to ensure that if the pipe is manufactured differently, you'd always have an identification. But there are indications on what you call those pipes to lead us to believe that they are part of what Mr. Salas mentioned earlier, which would be jointers. Specifically the fact that the long seams were ground down on that leads one to believe that this was part of a process intended to go back on the hydraulic expander. You can't have offsetting long seams in that expander without damaging the pipe. So the fact that those long seams were ground down, it leads us to believe that it was at least intended to go there. Whether it did or not, there's no proof of that.

MR. CHHATRE: Okay. Now, both Mr. Salas and you mentioned about the jointers. What are the typical lengths of the jointer that you guys have discovered in Lines 101 and 109? Because during my earlier questioning this morning, the issue of jointers came up and that there may be jointers in Lines 101 and 109. What would be a typical length of those jointers? And either of you can answer that question.

MR. FASSETT: I would like to, if that's okay.

A jointer refers to actually something that happens at the mill. I think we've been using pups and jointers synonymously. Pups from a construction perspective typically means a short spool of pipe that's welded to a fitting like a valve or 90-degree elbow. The jointer is, as defined in the API standard even then in 1948, was the idea that the pipe is made, in this case it would be made to 29-1/2 inch diameter. It's put on a hydraulic expander. It's expanded hydraulically and then it runs through a series of hydro tests, et cetera.

If during that process the long seam fails, the standard allows the manufacturer to remove the portion that failed and then weld up the smaller pieces to make what's called a jointer, and the intent is to go back on that expander and go through another hydro test of 10 seconds.

So for Line 101 and 109, I don't believe Line 109 had any 30-inch diameter pipe. Line 101, well, there's a short section we inserted a camera into it and found that all of the -- that there was a weld for all of the pipe. Where we saw short sections, we saw them around fittings and valves.

MR. CHHATRE: Madam Chairman, the Technical Panel has concluded their questions at this time.

CHAIRMAN HERSMAN: Great. We'll take a short break. We'll reconvene at 3:30.

(Off the record.)

(On the record.)

CHAIRMAN HERSMAN: If everyone could take their seats. Welcome back. We'll reconvene, and we'll begin with the Parties questioning of the panel. And again, since they're PG&E witnesses, we'll wait and let PG&E and go last and do cleanup.

And so at this time, we'll start with the City of San Bruno for questions for the Tech Panel.

MS. JACKSON: Okay. Thank you, Madam Chair.

We have a few questions. I'm not sure who should answer this. I'll leave it to you, please. Your previous testimonies identified that there was no information -- I believe that this was Mr. Fassett's testimony -- no information that triggered concern about a manufacturing defect in Line 132. In addition, your risk assessment methodologies assign a low probability to materials failure such as what occurred in San Bruno. Obviously, we now know that the results were catastrophic. Do you intend to revise your risk assessment methodologies in light of the event?

MR. FASSETT: Yes, as Ms. Peralta mentioned earlier this morning, in light of this particular situation, the situation of no weld on the inside of a DSAW, we are not only just looking at that threat category, but also, as Mr. Salas mentioned, we brought in a third-party expert that's looking at our entire risk -- all of our risk management procedures. We're looking at areas of -- we're comparing them to code; we're comparing them to industry consensus, and we're looking for areas where we could exceed all of those.

MS. JACKSON: Maybe a short follow-up question to that last statement, and you mentioned before that you are looking as either a current or a future practice to compare your Integrity Management Program to the industry. To what extent was that program peer reviewed or otherwise compared or evaluated against the industry prior to the incident in San Bruno?

MR. FASSETT: So the 2007 audit that I referred to where an outside third-party expert came in, they were people who were very familiar with what used on the outside. We also are members of various committees. I mentioned a few of those that I'm part of and the information that we learn there is brought back to the company.

There's one area, for example, where we believed that further direction needed to be provided on when to use DA and ILI and hydro test in a complimentary fashion. So we have pipelines that we've DA'd and also follow up with ILI and vice versa. We went to the National Association of Corrosion Engineers. They agreed to open a committee. The committee is Technical Group 401, which is how to best use those tools, and that's been underway -- I think that group is about a year old now.

MS. JACKSON: Mr. Fassett, you mentioned earlier that a section of Line 101, that you had at some time in the past inserted a pig into Line 101. I wonder if you could describe for us where that was and what information was developed as a result of that investigation?

MR. FASSETT: I don't have the specific locations. I can provide that. I believe what I was referring to is -- I didn't explain the whole issue. When we saw what happened with this line, we took an evaluation where we looked at all 30-inch pipe that was installed prior to 1962, and if it didn't have a strength test on it, we reduced the operating pressure by 20 percent, which is an industry agreed way to do it supported by PHMSA. There is -- I think it's somewhere between 400 to 600 feet of Line 101, somewhere in the Mountainview area, where we took the line down and we put a tethered camera through it and we saw all of the inside of the pipe, and all of that 30-inch pipe had an inside long seam, but we didn't use an inline swimming pig. We used a tethered camera for that.

MS. JACKSON: Changing directions a little bit, and again to the panel member who's best able to answer, knowing that a portion of your high pressure gas transmission system has multiple welds in pup sections, would it be your assessment that your risk assessment methodologies have identified this as requiring greater scrutiny particularly given that your Peninsula lines are unpiggable?

MR. FASSETT: I'll take that. I think there's a distinction that needs to be made between a pup section and a jointer, which I believe as mentioned earlier, is what this is. We need more information -- and my understanding is the metallurgical group is doing this -- to understand what were the weld materials, what was the toughness, what was the yield? There's further information that we need to understand and I'm sure it will come out of this as part of the analysis. Right now we're just in the fact-finding stage. I'm sorry, but I think we're dependent on that at this point.

MS. JACKSON: My last question, and I think I'll address this to Mr. Salas. What, in your opinion, was the failure of PG&E's integrity management process to identify or predict the event that occurred in San Bruno?

CHAIRMAN HERSMAN: We need to be careful not to get into analysis here, but maybe if you could rephrase your question and ask them for a specific factual answer?

MS. JACKSON: In view of what happened in San Bruno, are there specific areas of the integrity management process that you are looking for improvement?

MR. SALAS: We are looking at the entire process, again, from beginning to end. Not as a function of having anything that concludes that it was broken or wrong, but just the fact that this event occurred causes us to step back and question everything that we're doing. I think when we get the root cause analysis, we understand the full probable root cause, we can then step back and then assess whether there was something more or different that we could have or should have done right now that's not apparent. Having said that, we do know we can go and benchmark our processes and procedures and methods against the industry and work to improve the process, and we're doing that.

MS. JACKSON: All right. Thank you.

CHAIRMAN HERSMAN: Thank you, Ms. Jackson, and I know it's very hard when we're getting so close on some of these issues. We'll go to IBEW.

MS. MAZZANTI: No questions at this time.

CHAIRMAN HERSMAN: Okay. PHMSA.

MR. WIESE: Thank you very much. I would point out that we have lots of detailed questions but I thought maybe we would, as a party to your investigation, we can pursue those with your technical folks maybe later, and I would keep comments and my questions at a slightly higher level.

I wanted to start these. I've got a series, and if I run out of time, I'll be glad to, if we get an opportunity, to come back to finish it up. But first of all, I wanted to compliment the NTSB. Sort of the emergency notice on risk assessment we think was very much on the spot and we responded quickly, as you had noted. We do plan to do a follow-up workshop hopefully in early July in which we can focus on these issues in greater detail really for the whole industry. And hopefully PG&E will be able to be a party to that and share information that they've learned as a result of this.

So my questions just in a quick sequence go to your comfort level with your records now and really just any observations you want to have. When you have lists and 100 percent confidence in a data stream that you integrate within your risk assessment, what sort of level, what sort of safety factor do you think is appropriate to apply to that particular outcome? Does that make sense to you? I mean, when you have 100 percent confidence in all your data streams going into your integrative analysis as a part of the risk assessment, you know, I think you feel a lot more comfortable going forward. So I just invite that for your comment.

MR. SALAS: So data improvement is an object of a huge, massive effort that we've currently been underway for some time here at the direction of the CPUC and the NTSB urgent recommendations. So we're in the process of pulling job file records that are really the working documents for managing the system that reside in a distributed fashion across the service territory. Our GIS system is sort of a summary of a subset of all of the data that resides there. So we're in the process of pulling data in very specific ways right now with regard to strength test pressure reports, and we're going to take that to validate MAOPs.

Having said that, we've got a broader plan that we're gearing up for right now as we get past these first phases, and that is to actually consolidate all of these historic records that we've got, work in these job files that reside in the field, which again can in some cases date back to the '20s and '30s, and begin to digitize them all to build them into a consolidated, more robust GIS system. We have a lot of standalone legacy systems and tools that we have for use within gas transmission, and so we have a plan to consolidate all of those and to migrate towards directional systems. So we intend to cure the system problem, you know, aggressively by moving towards consolidating, pulling in, simplifying and part of that process will be validation so that we're not just pulling records together, making sure that records agree, but actually doing field tests so that we can confirm on a rational basis that what's on paper is what's in the ground.

MR. WIESE: Thank you. I would just urge you to, you know, the integrity management rule clearly puts onus on the operator to make conservative decisions. You know, where your information is lacking or soft, you really need to apply a safety factor on that.

MR. SALAS: And that is, in fact, the method that's employed. Wherever there is an unknown, we use the most conservative factor for the given asset that -- consistent with the guidance.

MR. WIESE: I'll skip the question on risk assessment because I -- you know, I'm aware of the fact that you've done kind of a major, you know, look at your risk assessment methodology, and I think our state partners and ourselves are very interested in that and hope to work with you in a little more detail on that one.

I would ask for any comments you have -- you know, you've learned a lot of lessons going through this and you've looked at some of your assumptions. And regarding the stability of certain defects, particularly manufacturing and construction, I would just ask if you're comfortable with the current standards and regulations as it applies to your determination of stability?

MR. FASSETT: Well, the issue we're addressing, and it's in cooperation with our CPUC for the pipeline that was established using the historical pressure. There has been no specific direction that if the MAOP of the line was established using the historical perspective, what that means relative to a stable or unstable flaw. I think that would be an area that we are looking into further, and I think it would be a good area for the industry to look into.

MR. WIESE: And I'll close because I think my time is up. I would urge you -- I think there is additional information out there on DSAW that we all need to take a good close look at. So thank you.

CHAIRMAN HERSMAN: CPUC.

MR. CLANON: Thank you. Mr. Fassett, a couple of quick questions and follow-up. One of them is you mentioned being I think it was surprised about a particular failure mode here, and you mentioned talking to some other folks in the industry as well who were also surprised. Can you say more about what it is about this that surprised you?

MR. FASSETT: Ms. Peralta spoke to it earlier so I'll just emphasize. I've been at this not as long as some, but in my 20 years, the DSAW long seam has always been considered as, if you're going to join a pipe on a seam, that's the most effective way of doing it. So to have one missing, as I said, not only just approximately 4 feet of weld on the inside, but closer to 12 feet, because there was 3 cans, that's just a huge surprise.

We've been doing a lot of research on this since. At some point, after this vintage, the standard in the industry changed to where the weld on the inside was applied first and the weld on the outside was applied second. During this vintage, with this manufacturer, they applied the weld on the outside first. So you could see how through a quality control program that may confuse some people, but that's what surprised me.

MR. CLANON: Is the pipe segment that we're talking about, the one that was joined with a half a dozen pups or so, is that an unusual configuration or is that something that you see other places?

MR. FASSETT: I believe it's unusual. Generally, the only time I would see -- and I've been a construction supervisor. I've had welders and pipe gangs under my responsibility. Generally, you wouldn't see short pieces like that unless it was around a fitting. There was, I believe, a picture that was in one of the exhibits showing the project at the tie-in day, and there's three or four full-length pieces of pipe on the job. So why they would take short pieces of pipe and weld them up to fit that, leads me to believe it didn't occur, at least in some of the cases. There are certain pieces there that probably were not welded in the field.

MR. CLANON: Okay.

CHAIRMAN HERSMAN: I'm sorry. Mr. Fassett, can you repeat the last part of what you said? You trailed off a little bit. We couldn't hear you.

MR. FASSETT: I'm sorry. There's a picture in one of the exhibits, and I believe it's -- but anyway, there's a picture that was taken -- we believe it's the 1956 project -- pretty close to tie-in day, so when they were going to tie the new pipe into the old pipe. And in the background of that picture, you see manufactured segments, so formed 90-degree elbows, and you see full-length pieces of pipe. We know from the investigation that these short cans, some of them were completely square and some of them had a miter on them. So the miter joint, the angle, was probably made in the field. But the cans that didn't, that were of square equal length, I just had a hard time believing that a welder would have taken six pieces of pipe and spent all that time welding them together when there was full lengths of pipe leftover on the project. In my mind, if they were making up an angle -- and what we know from the field reports, is that each end of what's left out there is approximately the same elevation but is off in alignment by a degree and a half, 1-1/2 degrees. There appears to have been about a 3-degree change on one end.

When you look at the manufacturing report, it shows the cord lengths, the lengths of the pipe at the 3:00, 9:00 and 12:00 position. By looking at those lengths, one can determine if there was actually a miter, an angle cut in the pipe, or if it was intended to be square. And there's only two locations where there was any angle change needed, which would mean only two cans and not six cans.

CHAIRMAN HERSMAN: Mr. Clanon, I'm sorry for taking your time to make him repeat that, so I'll give you a couple extra minutes.

MR. CLANON: Okay. Thank you.

Let me direct this one to Mr. Salas. Mr. Trainor walked you through some questions about the Integrity Management Plan and how it does or should deal with manufacturer's defects that might worsen over time and how you might take that into account. The kinds of defects that we've talked about so far, and Mr. Fassett's talked about them, are particular kinds of design, like ERW and so on. I want to ask you to think about a different kind of defect, and that is a defect in knowledge about what's underground, particularly from this vintage, particularly from a period before computer records, when maybe your information is poor, at least in some areas, and we know in this area. How does your Integrity Management Plan deal with flat out uncertainty about what you know? How do you deal with not knowing what you don't know?

MR. SALAS: My understanding is there is a method for dealing with lack of information, and again it's a conservative value that's placed in. I think what then needs to be done, and again the experts are sitting next to me with regard to the program, is that we would need to have, based on the criticality of the attribute or aspect or data field that was missing, some set of steps taken to determine physically in the field what, you know, what the real case is, and in having the process and the methodology and the follow-up to ensure that, whether it's an excavation, a record search, a sample, whatever the mechanism would be, that we have a process that's defined based on the need to ascertain what's in the ground.

MR. CLANON: And finally, I think I'm probably out of time now, but I wanted to just raise an issue to see whether anyone else wants to pick it up, and that is whether there are potential threats that are specifically associated with aging pipelines, with pipelines of this vintage, the '50s and '60s. I think that about half of your existing today pipeline system was installed during the '50s and '60s. And Mr. Trainor began this line of questioning, but I'm curious to know whether you think that there are particular issues just associated with the aging of the infrastructure?

MR. SALAS: I have an opinion. It's probably not going to be terribly popular from an industry standpoint. I think our historical thinking as relates to asset age has been really, it's really not as much about age as it is about the condition of the asset, and it's really understanding the life of that asset and having that be the basis for how you treat it. I think, given our experience, we need to step back and challenge that precept, and I think that there may be a place to consider age or other attributes and I think that's part of why we are suggesting again a fairly aggressive modernization program. So while we talk a lot about integrity management and inline inspection and hydro testing, pressure testing, ECDA, all these different techniques to determine the character of pipe, I think what we haven't talked about is at what point do we simply replace pipe? And I think it deserves consideration.

MR. CLANON: Thank you. And I appreciate your letting me have another couple of minutes there. Thank you.

CHAIRMAN HERSMAN: You're welcome. PG&E.

MR. JOHNSON: PG&E has no questions.

CHAIRMAN HERSMAN: Member Sumwalt.

MR. SUMWALT: Thank you very much. Mr. Dauby, you had mentioned a little while ago during questioning what the design specs were for this pipe in this area. Can you tell me what those specs were again?

MR. DAUBY: For Segment 180?

MR. SUMWALT: Actually, I guess it was not you. It was Mr. -- who was it that said the specs. I guess it was Mr. Fassett.

MR. FASSETT: Yes. Specifically what I referenced was the information that we provided about the three purchase orders of pipe. One of those purchase orders had with it, or we sent in with it a report from Moody Engineering, which was then a third-party quality assurance specializing in mill inspection. They are today also. In that report, it called out the design of that pipe to be 3/8 wall, .375; 52,000 yield, double submerged arch welded with a hot applied asphalt coating which would be put on after the manufacturing of the pipe. That particular purchase order was cut about I think it was 6 months or so after the first purchase order, the 1948 pipe. So we have reason to believe that the process used then would have been the process that was used on the earlier pipe.

In that discussion of the long seam, it not only mentioned that it was -- back then they called them electric welded or electric fusion welded, today we call that submerged arch welded. But it specifically described that the design requirements for the long seam weld was to have an outside weld whereby the fusion would penetrate two-thirds of the wall thickness of the pipe and an inside weld that would do the same thing, so you would have overlapping of the two welds, increasing the strength and fusion on that.

MR. SUMWALT: So by today's standards, we would refer to that as a DSAW. Is that correct?

MR. FASSETT: That would be the colloquial term. I don't believe the code actually differentiates between it. They call it submerged arch welded, yes.

MR. SUMWALT: Okay.

MR. FASSETT: I'm sorry.

MR. SUMWALT: Thank you. And it's double submerged because it's welded from the outside and from the inside. That's what the double part of that means, correct?

MR. FASSETT: Yes, sir.

MR. SUMWALT: So if that's what the design specs call for, why was there confusion in the PG&E records concerning this being unseamed pipe or seamless pipe?

MR. FASSETT: As Mr. Daubin described earlier this morning, an accounting voucher was used. The slide that was put up, and I'm sorry I don't remember which one it was, otherwise I'd ask for it to come up, showed that there is an accounting code or the material code which called out essentially what I just said, X52 DSAW, but the description that was typed manually at that time was one of seamless.

MR. SUMWALT: Okay. That was the discussion about the journal entry and --

MR. FASSETT: Yes, sir.

MR. SUMWALT: Yeah, I've got that presentation right here. So thank you.

Mr. Salas, this question is just -- well, let me go back just for a second before we move to Mr. Salas, and that is that -- Mr. Fassett, you had said that from a quality control point of view, quality assurance perspective, if somebody had to inspect the weld from the outside, you could see that the weld was there or not there, but if you went inside the pipe, it would be -- it's easier to miss an inside weld being not there than it is from the outside. But I think I'm looking at an interview from a retired employee, in fact, a PG&E employee. In fact, he's the one who took the photograph that you referenced earlier in 1956. He said that his job was, in fact, to crawl through that pipe and look at it, and he said the thing I remember the most is myself and another crawl through the pipe before they tied it in to look for debris, welding rods, tools, old lunches, jackets, wild pigs and anything you -- so I wonder why this got missed?

MR. FASSETT: So his purpose was to crawl through and look for those things, typically on the bottom of the pipe. I believe there's also discussion in that transcript where they say did you look for the long seam, and he said, I was in a pipe; my head was down; all I could look at was at the feet.

That's significant because when we weld up pipes, it's been for years the standard to put the long seam weld at the 10 and 2 position, is typical for a pipeline. So if he's looking at the bottom of the pipe, that may explain why.

MR. SUMWALT: Okay. Good. Thank you.

CHAIRMAN HERSMAN: Member Weener.

DR. WEENER: Thank you. The integrity management, of course, is predicated entirely on knowing what's in the ground, and looking at some of the material properties of the so-called pups, they seem to have considerably different properties in terms of yields and even grain structure. Given that these pieces of pipe are probably different than the line pipe, these pups, if you pardon the analogy, might better be called mongrels because of the mixed or uncertain parentage. What techniques do you have to actually go in and find these, presuming that these were perhaps not the only instances of this kind of piping?

MR. FASSETT: One of our challenges is, in anything that happens in integrity management, is to -- anything requiring mitigation, is to determine if that situation was unique, finite or systemic. And what we're doing to address it now, we believe this is unique; however, we didn't stop there. We took the 30-inch pipe, pre-1962, and I know I said that before, but I want to explain a little bit. Pre-1962 is for a couple of reasons. We looked at all the pipe purchased, all the pipe installed from really 1948 and continued to run it out and there's a spreadsheet that shows the detail. The short of it is by about 1959, we were bringing in new pipe, so any pipe that was leftover from these purchase orders would have been installed.

And the other significance about 1962 is that by the end of 1961, our State of California had enacted General Order 112, which is the maintenance and operation safety standard for the state at the time. One of the things they required was a strength test for any pipe intended to operate above 20 percent of its theoretical strength. So we took all the pipes down that did not have a strength test on them that were 30-inch diameter that was pre-1962 pipe by 20 percent.

We've also, per the direction, we've been looking at all of our records in determining NCHAs, cull method 1. We've been looking at all of those to determine where we've had strength tests and where we don't and working towards addressing those areas where we didn't. Cameras are being used on the 30-inch pipe. As we get more pipe that we think may be of this vintage and concern, we'll address those as well.

DR. WEENER: Now, it was mentioned earlier that there were three suppliers of pipe that were kind of in question. Have you been able to kind of work this backwards and figure out where that pipe happens to be?

MR. FASSETT: Yes, sir. Two of those suppliers, one was a mill and one was a distributor, and it was confirmed that the pipe that was purchased from them was consumed on those jobs they were purchased for. The three purchase orders we refer to came from one mill between 1948, 1949 and 1953, on three specific pipelines: 132, 153 and 131. Both of those pipelines have had the pressure reduced by 20 percent, and we're getting permits and we're doing efforts to get inside of them.

I referenced a technology that we're working with a couple of folks on to improve our ability to go in hot, which means that we can go through a lot more pipe a lot easier than a tethered camera, which would be dragging an extension cord and a fiber optics camera and things like that. So in short, that's what we're doing.

DR. WEENER: Okay. Then one final question related to testing, and you described earlier the problem with hydro testing in terms of having water residual -- residing in the pipe, I should say. But there was mention made of other kinds of pressure testing. Am I making a correct assumption that we're really talking about pressurizing a pipe with a compressible fluid? And if so, what kind of hazards does that present?

MR. FASSETT: Yes, sir. We talk about it as hydro test but the general category is called a strength test, and there is directions on when we need to use water to strength test that pipe and when we can use a pneumatic. We could use compressed air or nitrogen. There's restrictions on that because if you increase the pressure on a pipeline using a non-compressible fluid, water, then when the pipe fails, the energy is dissipated out through the water and any crack or any flaw that's created by that is arrested quicker. If you use a pneumatic, you have to get the pressure down so that flaw may run farther. So there are restrictions on when you can use pneumatics and, for the most part, we tend to use water.

There's issues with perhaps a vintage bridge that's been around a long time. We're not sure we want to put a lot of water on that bridge. There's issues associated with those kinds of things.

DR. WEENER: Thank you.

MR. SALAS: If I might add, I think the other concern that we had is the potential with regard to hydro testing we're activating a latent defect. And so we could, in fact, create an at risk situation that wouldn't be visual to us, and thus we think that the test methodology that's selected really needs to be tuned to the pipe in question as opposed to a blanket policy with regard to how to prove pipe.

CHAIRMAN HERSMAN: Member Rosekind.

DR. ROSEKIND: For the whole panel, I'm curious how you measure the success or effectiveness of your Integrity Management Program. A lot of times with processes, it's the number of inspections that are done, et cetera. How do you know it's working? What concrete metrics are used to determine whether the program's effective or not?

MR. DAUBY: I can try to address that from the inline inspection program perspective, because on every inline inspection that's performed, we do calibration digs based on information that we received from our inline inspection vendor, and then we compare the results that we obtain from those field inspections to what the vender predicted, and we have specific forms that are filled out as part of the process to confirm that the results are matched within the tool tolerance range that it is -- the service we're purchasing.

DR. ROSEKIND: Other metrics?

MR. DAUBY: In regards to -- I think Mr. Fassett indicated earlier --

DR. ROSEKIND: And again, I'm talking broadly about the program. Some of these are very clear, calibrations, et cetera, and that's what I'm getting at. I'm trying to get a feel because the program covers so many different elements, how do you know it's working for you?

MR. SALAS: I think, Member Rosekind, you raise a really good point, and it's a point that I think we need to pursue. There isn't what I would consider a large, kind of a single macro index or a way to frame all of the individual mechanisms that we would use to test effectiveness in some integrated holistic fashion, and I think that's worthy of us pursuing further. We look at it in a number of different ways, in a number of different facets, but we haven't got kind of the definitive integrated, you know, metric.

DR. ROSEKIND: And an Integrity Management Program didn't exist in 1956. So I'm sure if somebody, and maybe this was part of the procedure, just walking through or crawling through the pipe, what would have been the quality assurance sort of process, especially when this pipe was moved, that should have or would have been gone through just to make sure the integrity of the pipe was appropriate?

MR. FASSETT: There were various guidelines at the time. There was the American Society of Mechanical Engineers in 1955. That was the first time that strength testing was recommended, but that was for pipelines that operated or intended to operate over 30 percent. In 1962, that was changed to pipelines that were intended to operate over 20 percent. There was x-raying of girth welds --

CHAIRMAN HERSMAN: Could you pull the microphone just a little closer to you?

MR. FASSETT: I'm sorry. So there was a guideline that says you should x-ray, for example, your girth weld, the circumferential weld around that time, and the sampling frequency was given as -- the minimum was 1 in 100 joints. We have records from the 1948 project that purchased this pipeline where they were sampling at a 10 percent rate using x-ray of the girth welds.

There were tests, air tests that were done on them, but typically they are done at around 100 pounds or a little higher because they're looking more for leaks than they were to strength test the fabrication of the pipe. At that time the quality assurance on the pipe itself was a hydro test at the mill.

Between 1948 and 1953, the API, American Petroleum Institute, was calling for an 85-percent test for 5 seconds. PG&E called for a 90-percent test for 10 seconds, and it's called the hammer test. They would hit the long seam with a 2-pound hammer during that 10-second test.

DR. ROSEKIND: And do you have records showing that those quality assurance procedures in place at that time were actually conducted when this pipe was moved?

MR. FASSETT: The Moody Engineering report I referred to associated with the second purchase order for the construction of

Line 153 recognizes that that was done, and when you get a Moody Engineering report, when they sign it, they are certifying that the specifications were met.

DR. ROSEKIND: So you don't get the results of those tests per se; you just get somebody signing off that it met our requirements?

MR. FASSETT: There's portions of it. I don't recall seeing a list of strength tests. There is a list of what pipes failed and how many joints they didn't pass. There's a list of the chemistries taken from each of the batches. There's yield strengths and other things like that that are reported in that report.

DR. ROSEKIND: Okay. Thank you.

CHAIRMAN HERSMAN: Vice Chairman.

MR. HART: Thank you. Just to follow up on my question from the Operations Panel about where pigs come from, and Mr. Salas helped out with that answer, and I think you other two heard that answer. So again, the question of where do pigs come from and how much do you know about where these specific pigs came from?

MR. FASSETT: The pups or --

CHAIRMAN HERSMAN: I think we mean pups.

MR. HART: I'm sorry. You're right.

CHAIRMAN HERSMAN: We're getting our animals confused here.

MR. HART: Sorry. A little fatigue here, and maybe I'm hungry, too, so I'm thinking -- the pups is what I'm talking about, not the -- the mongrels we might say. Okay.

MR. FASSETT: And that was what I was explaining a little bit with Mr. Ravi Chhatre earlier. So there's a couple of places you can see short pieces of pipe. The most likely places are in the field construction near a valve because we want to -- at a valve, it's called typically a back welded joint. When we go in, the thing we're worried about with valves is we don't want any of the product from the weld of the circumferential welding process, the girth welds, we don't want any of those pieces to bounce around and lay themselves up against the valve because it would prohibit the valve from closing correctly. So we call for short sections of pipe that would be at least two diameters long, so that if any of that happened, it wouldn't roll into the valve. The valve is protected and then it's back welded and then it's outside welded. That's typically where we see that, or for a 90-degree elbow or a 45, that kind of thing.

What we've learned through this process or what came out in this process is this concept of a jointer, which as I mentioned earlier, that's if a pipe went into hydraulic expander and failed in there, they were allowed -- they are allowed even today, to cut that piece out, weld up pieces to make a full-length 30-foot joint at that time. And then the intent was to put it back on the expander, put it through another hydro test and if it passed that, then it was, you know, shipped out to get coated.

MR. HART: So if that piece came from a piece that failed, wouldn't it likely have a double longitudinal weld? Because these didn't, and I just wondered what source could it come from where they didn't have a double weld?

MR. FASSETT: I have an opinion. If you like, I could present that. There's a couple of things about this. One, that we believe it was intended to go back on the expander, as I mentioned earlier, because the long seams were ground down.

The expander has in it, there's what's called a relief or a groove where you would put the -- you would line up the groove of the long seam in that expander so that when the pipe got expanded out to it, the groove, the cap, the long seam weld, would go up into that groove and then the rest of the pipe is expanded out against the shell giving the correct diameter. If that cap isn't in the groove, then as it expanded out, the pipe would be deformed because the cap would be deforming it. So we believe it's intended to go back because when you weld these short pieces up, you don't weld the seams in line. You weld them offline intentionally. So if you were to put that in without the caps being ground down, they would get deformed.

The other thing that we know -- and this is speculation; we just understand it from the way mills work, is -- my understanding is it would not be out of the ordinary for them to have taken sheets of plate that had been trimmed off for whatever reason and roll them into short sections to be used as templates to set up equipment, which may have been just a process of I need a piece of pipe to set it up to set the diameters or to get the weld right or that kind of thing. Again, it's speculation. Those cans may have been laying around and they used them.

We know from the reports that there was a lot of demand on 30-inch double submerged arc welded pipe in 1948 and '49. There was a delay of the order by 3 months because of the demand. They were pulling plate from wherever they could find it. It's just speculation.

MR. HART: Thank you.

CHAIRMAN HERSMAN: Maybe to follow up on that question since the Vice Chairman just asked, the inspection of the pipe in the materials lab that involved representatives from PG&E as well as other parties, really determined that the weld quality on those pups segments, some of them, was extremely poor. Would you agree?

MR. FASSETT: On the girth welds, yes.

CHAIRMAN HERSMAN: How about the longitudinal, the long seam that was only 50 percent, welded only from the outside, not the inside?

MR. FASSETT: Yes. Also, that was the seam I was referring to that didn't get a weld, yes.

CHAIRMAN HERSMAN: Right. So given that the explanation that you provided about the pre-1962 pipe was, if it was in the factory they would do the hydraulic test, the hammer test. Is there any indication that these pipe segments went through those?

MR. FASSETT: The only indication is that I believe there was an intent to go there because they ground the caps down. There's no evidence that they actually made it there.

CHAIRMAN HERSMAN: Is it conceivable that these could have been welded in the field?

MR. FASSETT: I don't believe so. The amount of effort and energy it would take in the field, I don't believe you could get a cylinder that would look anything like what needed to go in, plus they had pipe left over from the job.

CHAIRMAN HERSMAN: Well, why wouldn't they have used those other potential pieces that are pictured in the photo? Why would they go to the trouble to have to weld six different segments of pipe together when they had, and I think you earlier said, they could have done it with two?

MR. FASSETT: That's why I believe that some of that pipe had jointers in it. The description in the API standard at the time was that the girth weld, when you weld these together, it's a very flat weld. It's not a weld that you would typically see in the field. They tend to be what we would call a nickel high and a dime wide and looking like a row of dimes.

There's a couple of these that don't look like that. They're very flat. That's relevant because by the time you put about 3/8th to a 1/2-inch of hot applied asphalt and felt over that, someone in the field wouldn't see the impression of that girth weld. So it's likely they could have taken a piece, a full-length piece from their perspective and cut it down.

CHAIRMAN HERSMAN: So what was the protocol for field inspections in 1956 when this pipeline was relocated in that neighborhood and these pieces were put in? Is there any standards for inspections, field inspections when new pipeline is installed, either PG&E inspectors to go through or state inspectors?

MR. FASSETT: What we found was and what we've provided were requirements for contractors that required various controls. For PG&E crews, we haven't discovered a specific procedure that told them what to do and how often to do it. There's some indications on the pipe, and it's still being investigated, that may indicate that at one joint there was a girth weld x-rayed, and I believe it's the joint between pup 4 and pup 3, but other than that, we've not found anything.

CHAIRMAN HERSMAN: Are there requirements today for field inspections for pipe installation that are different than '56? Someone to go behind the welding crew to take a look at the welds to make sure their quality is good?

MR. FASSETT: Yes. For any pipeline, starting in 1962, with the implementation of CPUC General Order 112, for any pipeline intended to operate over 20 percent of its theoretical strength, there is a requirement for strength testing and there is a requirement that all of the girth welds, 100 percent of the girth welds are x-rayed.

CHAIRMAN HERSMAN: What about the longitudinal seam welds?

MR. FASSETT: That relies on the quality control from the manufacturing, and in 1963 API standard 5LX, and I believe it's the 11th Edition, requires 100 percent of DSAW long seams to be, they call it radiologically inspected, which I would call x-rayed.

CHAIRMAN HERSMAN: All right. I have a number of other questions. I only got to one, but that's okay. We'll go to the Tech Panel.

MR. CHHATRE: Thank you, Madam Chairman. I'd like to continue following up the discussion on the pups with Mr. Fassett, and my question is regarding pup 1, what attributes allow you to hypothesize that this is a factory pipe section and not otherwise, these are factory and not otherwise?

MR. FASSETT: The items I mentioned earlier, the cross-section of that weld looks like the description that's provided in the Moody Engineering report, that it was intended to have a weld on the outside and the inside, and the design of that weld was intended to penetrate two-thirds of the wall thickness. That cross-section shows that the weld did penetrate two-thirds; it just didn't line up on the long seam and therefore only about 50 percent of that weld got there. As well as the ground down long seam caps.

MR. CHHATRE: Are there any other attributes like a stamping on the pipe or pup, any other attributes that identify the manufacturer?

MR. FASSETT: So the pup immediate to the south of that, I think it's shown as LS, has the labeling from the Consolidated Western. There's a stamp embedded into the side of pup 4 that we're trying to find out if it was Consolidated Western's brand; it may be. And then there's some labeling on the inside of other sections there that are in alignment with the labeling that would have come from Consolidated Western.

MR. CHHATRE: And did the lab find defects like the ruptured pup in those three pups that you identified in the seam weld?

MR. FASSETT: Pup 4, yes, they said that there was a repaired long seam on the inside of it.

MR. CHHATRE: The other two pups you mentioned, had a stamp that was DSAW?

MR. FASSETT: The brand I was referring to is in pup 4, and pup 4 is described as having a hand-applied arc welded repair or long seam on the inside of it.

MR. CHHATRE: And does it identify the manufacturer?

MR. FASSETT: We've asked for further research to understand if that's the brand we're looking for and my understanding is that it's still under investigation.

MR. CHHATRE: But does that pup 4 have any manufacturer stamp on it that identifies the manufacturer?

MR. FASSETT: There is a stamp on it that meets the description of how brands were made by Consolidated Western. It comes from the 1998, I believe, ASME report on the history of pipe manufacturing, and we have been researching to see whether that's the brand Consolidated Western used. Consolidated Western was absorbed by another mill in, I believe, 1956.

MR. CHHATRE: But nothing has been confirmed yet; is that correct?

MR. FASSETT: My understanding is it's still being researched through the metallurgical group.

MR. CHHATRE: Now, the metallurgical lab report, which PG&E has a copy of, indicated that pup 1 had yield strength lower than the specification and the sulfide stringers or grains, if I may, only occurred at 90 degrees to the pipe dimension. How does that compare with the manufactured pipe?

MR. FASSETT: So typically when a 30-inch or a 30-foot long pipe is made, you have a plate that's longer than 30 feet, and then it's placed in a series of presses and it's bent into a U and then it's bent more into a circle, and then it's run through. So the orientation of those grains through that process would be lengthwise. You would expect them to go the 30-foot length.

The orientation of the grains in pup 1 were going the other direction, which is more an indication that somebody may have taken some plate, and again they're trying to use as much plate wherever they could, a plate that may have had a defect in it that they had to shear off, and they took that plate and they then rolled it -- essentially the longest section would have to be 7'10" long to make a 30-inch OD pipe. They then bent it, the 4-degree access -- or the 4-foot section, they U'd it and then rolled it. So the grain structure would be going opposite of --

MR. CHHATRE: So is it reasonable then to say that that somebody is not Consolidated?

MR. FASSETT: It's reasonable to say that Consolidated was using that. My speculation was we know they -- or I believe we know that they've used short pieces of pipe that they've made to set up equipment because they wouldn't want to get the settings wrong and destroy a full piece of pipe, so they'd use short pipes. But as I said, it's speculation and I believe it's still being researched by the metallurgical group.

MR. CHHATRE: My time is coming up. I'll ask you a last question. In this whole discussion of pup, and I will only made a few notes, you must have used the words "=I believe or it's hard to believe or I don't understand, probably if not every sentence, every other sentence. And my concern is how does strong belief support a contention that maybe we have a DSAW welding problem here? We don't really have any confirmatory facts and is PG&E doing something to provide those facts, or we are just drawing this conclusion based on beliefs?

MR. FASSETT: We're waiting for the root cause to come from the NTSB investigation. That should tell us what the specific issue is. We didn't want to not do anything. So we're taking our best effort, using the information we have and trying to mitigate the concern but, correct, we don't have a root cause yet, and when we do, then we'll look at what we did and determine if that was enough or we need to do more.

MR. CHHATRE: Madam Chairman, the Technical Panel would like to conclude the questions at this time.

CHAIRMAN HERSMAN: Thank you. How about the Parties? Do we have anybody requesting a second round? PHMSA.

MR. WIESE: Okay. I promise to make it brief. I just wanted to ask another question regarding stability and sort of our comfort with the stability of defect, particularly manufacturing and construction. To what extent does your Integrity Management Program allow for the interaction of various defects? So, for example, and I'm not speculating as to cause. I'm just saying it's possible for multiple defects, as I think Bob would know, to interact together --

CHAIRMAN HERSMAN: Can you pull the microphone just a little bit closer to you and restate your question?

MR. WIESE: Okay. Sorry about that. I'm really just trying to get at the question about the extent to which your program looks at the interaction of various defects, and it could be anything from subsidence to seismic activity. How does the assumption regarding the stability of the welds, for example, how is that influenced by other potential risk information? Is it sort of the Integrity Management Program requires an integration of that information? So I'll just turn it over to you, Bob, probably, I guess.

MR. FASSETT: So through the risk calculations, that equation I mentioned earlier, there's factors associated with things like outside force and external corrosion and third-party damage, things like that. All of that has different weightings associated with it, and specifically I'll talk about the interaction between external corrosion, concern about older girth welds that were used before the requirement for 100 percent x-ray, and outside force.

In California we have earthquakes. So we know from the U.S. geological maps where the pipelines run and we know what the expected acceleration from a seismic event would do. So we take that and, for example, if I have pipeline with the older girth welds in it -- and cathodic protection wasn't put on the line until it was required, so maybe it's got 20 years without corrosion control on it; it's got these girth welds. We would look at that. Those pipelines would come up in priority, which may move it and likely would move it to the first part of the baseline assessment program. 132 is in the first part of that program. That would be an example of how it's treated, and then the tool selection would be used to make sure we're assessing correctly.

MR. WIESE: Okay. Thank you very much. I would, if you'll allow me one quick question, I'd like to pick up on a line of inquiry that Paul Clanon started.

CHAIRMAN HERSMAN: Sure. Hopefully, we can get a quick answer, too.

MR. WIESE: Okay. Great. Sorry. That Mr. Salas commented on, and it has to do with aging infrastructure. I think there's been a lot of debate out there, and I know it's not as simple as just age, but age is a consideration, as you said. I wonder if you have any ideas on how pipeline operators could improve the ability to re-qualify their infrastructure as fit for service, you know, in addition to just running ILI, but, you know, it's a combination of things, whether it's repair, rehabilitation, replacement, you know, hydro testing, anything you don't have complete records on. I just welcome any comment on that.

MR. SALAS: We've had a large body of work connected with developing a decision tree that takes pipe of various attributes through a series of steps to either qualify or ultimately, you know, recommend rehabilitation or, in fact, replacement and we would be happy to share that, you know, as the room is interested. It's got a lot of different legs and streams, and it's a fairly complex, you know, set of decision points, but I think it's advancing the discussion in terms of getting us to the decision probably sooner than we might otherwise for pipe replacement.

CHAIRMAN HERSMAN: Thank you. Member Sumwalt.

MR. SUMWALT: Thank you. I'll make this quick.

Mr. Salas, this question is really one that I'm interested in, but it doesn't relate directly to what we're talking about, so my apologies. But oftentimes the Board members go out and we talk to the industry, we talk about things like the cost of an accident. I know that you're well versed with the monetary value of this accident, monetary cost. But I'm curious, what percentage of senior management's time is preoccupied now with this accident over the last 5-1/2, 6 months?

MR. SALAS: Member Sumwalt, that's a tough question. I would say the vast majority of senior management, and I would include our board of directors in that. So we have our board, we have executive management, corporate management as well as senior management within the utility, not only those that are in the technical disciplines, but across a number of the other organizations. So I'd say this is consuming a very material proportion of our time.

MR. SUMWALT: Yeah, and that's what I was thinking, and I appreciate that. There's a tangible answer there that we can take out to the industry because that's sort of a hidden cost. That time is time that you're not able to spend with the strategic and tactical direction of growing the company. So I appreciate your answer there.

Thank you very much, Madam Chairman.

CHAIRMAN HERSMAN: You're welcome.

I have a couple of final cleanup questions, and if possible, if we can get quick answers to these. About 7 percent of the total gas transmission miles are in HCAs across the country. I'm curious what percent of the miles on the PG&E system are HCAs?

MR. FASSETT: Of HCAs, if you only look at HCAs, it's 20 percent. If you look at what we inspect in our baseline assessment plan, it's 15 over 50, so it's half again more. It's about 30 percent.

CHAIRMAN HERSMAN: I'm sorry. Can you just speak up at the end there? Twenty percent are HCAs and --

MR. FASSETT: So we're required to file a baseline assessment plan of all the mileage, that's 1500 miles. The HCAs within that is 1,000 miles. The 1500 miles, which is all the pipe we would assess in our baseline assessment plan, represents 30 percent of our transmission.

CHAIRMAN HERSMAN: Okay. Thank you.

And can you explain how the GIS is populated where information is uncertain or incomplete? So, for example, in this section of the line there were assumptions made and -- as this information was loaded into GIS. I go back to a question that Mr. Wiese asked about making the most conservative evaluations. In this case, were the most conservative assumptions made with respect to this section of pipe?

MR. FASSETT: Segment 180, the information came from an actual document that said, according to the document, that it was seamless 42,000 yield. So there weren't assumptions used. It was referenced from a source document.

CHAIRMAN HERSMAN: And the source document was incorrect?

MR. FASSETT: That was the document that Mr. Daubin discussed earlier this morning.

CHAIRMAN HERSMAN: Okay. And I think this has been discussed by several folks today, but I just want to close the loop on it, and I was very encouraged by some of Mr. Salas's remarks. Mr. Fassett, you talked about pipeline standards being improved in 1962, and we heard about pressure testing requirements in the early 1970s. We heard about pipe that was installed in the 1990s having requirements to be able to be inline inspected. We heard about cathodic protection that's been added.

And so I think that rhetorically we can see that each of these actions over the years have been an additional layer of safety, whether it's on the manufactured product, the inspection of the product, maintenance of the product, all of those are layers that have been added on. Is there any correlation on your system -- I'm not asking you to speak about nationwide, but on PG&E, is there any correlation between leaks and the age of the pipe?

MR. FASSETT: There is a correlation between leaks and corrosion. Corrosion is the aging factor of our pipe. So, yes, there is a correlation.

CHAIRMAN HERSMAN: Okay. And we know that the primary cause of most releases is third-party damage, but following behind that is corrosion.

MR. FASSETT: Correct.

CHAIRMAN HERSMAN: And so there is a link, a correlation between corrosion and leaks and the age of the pipe?

MR. FASSETT: Right. So if you're seeing a trend down in leaks.

CHAIRMAN HERSMAN: Okay. And is there a correlation between ruptures and the age of the pipe, not just leaks, but major events where you're going to have an explosive release of gas?

MR. FASSETT: I pause because I'm stuck in the old paradigm where corrosion is the time-dependent portion of it.

CHAIRMAN HERSMAN: Okay. So it'll go back to corrosion again?

MR. FASSETT: Relative to corrosion, but most ruptures are associated with third-party damage.

CHAIRMAN HERSMAN: Yeah, but this one is not. We're not seeing the hallmarks of third-party damage in this event nor are we seeing primary indicators that lead us to corrosion.

MR. FASSETT: If you were to call this manufacturing, that's a very small percentage of why pipelines rupture.

CHAIRMAN HERSMAN: Is there a correlation between manufacturing defects and age?

MR. FASSETT: If they become unstable, and they're associated with a lot of cyclic fatigue, then the more you cycle the pipe, the less time you have before it fails.

CHAIRMAN HERSMAN: Okay. Very good.

Thank you all so much for a very productive day. Thanks to this panel's witnesses, to Mr. Salas for being an encore witness for us today. Thank you for the answers that you've provided and your willingness to appear before us today. It has helped advance our investigation, both to the witnesses on Panel 2 as well as Panel 1.

We will reconvene at 9:00 tomorrow for Panel 3 on public awareness.

(Whereupon, at 4:40 p.m., the hearing was adjourned to reconvene on Wednesday, March 2, 2011, at 9:00 a.m.)

CERTIFICATE

This is to certify that the attached proceeding before the

NATIONAL TRANSPORTATION SAFETY BOARD

IN THE MATTER OF:	PUBLIC HEARING ON NATURAL GAS PIPELING EXPLOSION AND FIRE SAN BRUNO, CALIFORNIA SEPTEMBER 9, 2010
DOCKET NUMBER:	DCA-10-MP-008
PLACE:	Washington, D.C.
DATE:	March 1, 2010

was held according to the record, and that this is the original, complete, true and accurate transcript which has been compared to the recording accomplished at the hearing.

Timothy J. Atkinson, Jr.
Official Reporter