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CONSUMER PROTECTION AND SAFETY DIVISION
CALIFORNIA PUBLIC UTILITIES COMMISSION

REVISED
REPORT AND TESTIMONY
OF
MARGARET FELTS

I.11-02-016

San Francisco, California
March 16, 2012

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ATTACHMENT – RESUME OF MARGARET FELTS

APPENDICES

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Soon, Appendices and other reference documents associated with the recordkeeping OII will be available on the Commission website. To access these documents, please visit http://www.cpuc.ca.gov/PUC/events/110224_sanbruno.htm, and search for the subject area called "Reference Documents for CPSD Reports in Recordkeeping Penalty Consideration Case".

1 **1.0 INTRODUCTION**

2 In the immediate aftermath of the 30” gas transmission line explosion in San Bruno on
3 September 9, 2010, Pacific Gas and Electric Company (PG&E) told the National Transportation
4 Safety Board (NTSB) it was a seamless pipe that had failed. PG&E based this statement on data
5 from its electronic Geographic Information System (GIS), the primary source of information
6 about the design and construction of its pipeline system. Of course, anyone viewing the remains
7 of the pipe section lying on the ground in San Bruno could clearly see that the pipe had split
8 along a longitudinal seam. This initial bit of bad data was only the tip of the iceberg.

9 On January 3, 2011, the NTSB issued several safety recommendations urging PG&E to
10 search for all traceable and verifiable records to support the maximum allowable operating
11 pressures it was using for its transmission lines. If PG&E could not find records, the NTSB
12 recommended that PG&E hydrotest the lines to prove their integrity.¹ Immediately following
13 receipt of the NTSB Advisory, the Executive Director of the California Public Utilities
14 Commission (CPUC) ordered PG&E to comply with the NTSB recommendations, and on
15 January 13, 2011 in its Resolution L-410, the CPUC ratified its Executive Director’s order. The
16 CPUC then instituted a formal investigation to determine whether PG&E violated any provision
17 or provisions of the California Public Utilities Code, Commission general orders or decisions, or
18 other applicable rules or requirements pertaining to safety recordkeeping for its gas service and
19 facilities.²

20 This report considers PG&E’s recordkeeping practices from an engineering perspective,
21 focusing on two primary areas: 1) recordkeeping issues related to the September 9, 2010 San
22 Bruno incident, and 2) recordkeeping issues related to the integrity management program and
23 integrity management risk assessment model used to prioritize the replacement of pipe within
24 PG&E’s system.

25 **2.0 RECORDS ISSUES RELATED TO LINE 132**

26 This section highlights records related issues that can be tied directly or indirectly to the
27 pipe failure and explosion at San Bruno on September 9, 2010. Some of the records issues are
28 revisited in more detail in Sections 3.0 and 4.0 of this report. Those sections discuss PG&E’s

¹ NTSB Advisory to PG&E dated January 3,, 2011 (www.ntsbgov/doclib/reclatters/2010/P-10-002-004.pdf).

² Order Instituting Investigation (OII) No. I.11-02-016, February 24, 2011.

1 integrity management program and risk assessment models and the data from records that is
2 necessary to make such a risk assessment program fully functional.

3 **2.1 Reused Pipe in Segment 180 of Line 132, Project GM 136471 in 1956**

4 After the San Bruno incident, PG&E researched its records in an effort to determine the
5 source of the failed pipe and produced to the NTSB a pieced together summary of new and
6 reused pipe used in the installation of Segment 180.³ However, after searching through all of its
7 records, PG&E was still unable to identify records that documented the source of the one piece
8 of pipe that failed.⁴ If PG&E had kept orderly records of the purchase, installation, salvage,
9 reconditioning, inspection, and reuse of pipe installed in its transmission system, PG&E would
10 not have selected that piece of pipe for project GM 136471, because it did not meet PG&E's own
11 specifications for high pressure transmission pipe.⁵ NTSB lab results from thorough testing and
12 inspection of the welds in the pipe section that failed at San Bruno show that the poor quality
13 welds would have been visible to the naked eye.⁶ Upon visual inspection, this piece of pipe
14 would have been scrapped.

15 Without records about the source, specifications, or history of the pipe, it was possible for
16 pipe to be salvaged, sent out to be re-wrapped and delivered to the construction site without
17 anyone knowing or being able to observe the condition of the pipe.⁷ The absence of pipe
18 specification records and the absence of a tracking system for salvaged and reused pipe makes it
19 impossible to determine if there are other pieces of pipe that do not meet minimum specifications
20 for high pressure transmission line service installed elsewhere in Line 132.

21 **2.2 The Maximum Operating Pressure for Line 132 Based on Historical**
22 **Records – An Example of PG&E's Poor Recordkeeping Practices**

23 During this investigation, PG&E produced voluminous historical records about its facilities
24 and the operations of those facilities. The records were difficult to review because PG&E's record
25 system lacks organization and many documents are missing. Over the course of this investigation,
26 various records relating to the history of the Maximum Allowable Operating Pressure (MAOP) for

³ Response to DR 3 Q 11 and NTSB_460802.

⁴ NTSB_460802, p. 6.

⁵ NTSB_460278, p. 4 and 10.

⁶ NTSB Summary Report and NTSB 469689, NTSB Report, Office of Research and Engineering,
Material Laboratory Division May 17, 2011, document no. 469689.

⁷ Based on author's review of PG&E records in the ECTS database.

1 Line 132 were assembled in chronological order, extending from 1965 to present day. The MAOP
2 history for Line 132 is set out in detail in this section and in more detail in Appendix 1.

3 PG&E's Standard Practice 1606, dated August 1965, shows the MAOP of line 132 to be
4 400 psi.⁸ The MAOP for Line 132 remained set at 400 psi until 1976. PG&E appears to have based
5 this MAOP on the grandfather clause, which allows an MAOP based on the highest operating
6 pressure experienced between 1965 and 1970. PG&E documented a peak pressure of 400 psi for
7 Line 132 in 1968.⁹ However, as described below, there are numerous examples of PG&E's
8 inconsistent positions about its MAOP for Line 132 in its records, which are compounded by the
9 lack of any records explaining these discrepancies.

10 An internal PG&E letter dated August 15, 1978 says, "Information previously submitted by
11 San Francisco Division regarding MAOP based on the highest operating pressure within the five
12 year period prior to July 1, 1970, should be corrected in accordance with the attached listing."¹⁰
13 The attached listing indicates that Line 132 MAOP should be corrected to 390 psig between Mile
14 Posts (MP) 35.84 and 46.59, based on pressure readings on February 23, 1968. There is a footnote
15 that says "date and highest operating pressure revised."¹¹ In association with this 1978 letter, the
16 revised MAOP of 390 psi, was entered into the hand-written MAOP log for Line 132 between Mile
17 Posts 35.84 and 46.59 and at the bottom of the official MAOP list, drawing 086868.¹² PG&E has
18 produced two versions of the MAOP log. One is described in the preceding sentence. On the
19 second version, someone lined out the entry of 390 psi and wrote "400 psi," adding a note, dated
20 December 10, 2003, "See note – based on 10/16/68 & 10/28/68 Milpitas Term Records."¹³ Thus, in
21 2003, PG&E edited its historical record for the period 1978 TO 2003 regarding the MAOP on the
22 section of pipeline between Mile Posts 35.84 and 46.59. A matching, hand written note appears on
23 the 2003 revision 15 of Drawing 086868, which shows all of Line 132 at 390 psi. The note says
24 "12/10/03 Have RCDS showing 400 psi btw 65 - 70."¹⁴

Deleted: 1965 to 1970

⁸ P2-954

⁹ As discussed in Appendix 1, the authenticity of this record is questionable.

¹⁰ Response to DR 30 Q30, Supp Atch 2, p. 103.

¹¹ Response to DR 30 Q30, Supp Atch 2, p. 104.

¹² DR 30 Q 30 Supp Atch 3, p. 42 and P2-963, p. 4 note at bottom of page.

¹³ Response to DR 30 Q 30 Supp Atch 2, p. 102.

¹⁴ Response to OII_DR_5_Q9_Atch_4.

1 By its action in 1978 to lower the MAOP on one specific section of Line 132 PG&E
2 redefined Line 132 into two sections. The first section runs from the Milpitas Terminal, which is
3 Mile Post 1, to Mile Post 35.84. The MAOP for this first section was kept at 400 psi. The
4 MAOP for the second section, between Mile Posts 35.84 and 46.59, was listed as 390 psi. The
5 site of the 2010 San Bruno explosion is Segment 180 (MP 39.04 to MP 39.37) and, thus, is
6 included in this second section.¹⁵ From 1978 to 2003, the MAOP of Line 132, between Mile
7 Posts 35.84 and 46.59, was documented in PG&E's records as 390 psi.

8 Confirming that PG&E did intend to differentiate MAOP data for the two sections of the
9 pipeline, one MAOP binder includes a certification dated May 20, 1983, regarding the section of
10 Line 132 from MP 1 to 35.84.¹⁶ This certification is based on the highest pressure for a five-year
11 period ending July 1, 1970.¹⁷ A copy of the unsigned pressure log with the date of October 16,
12 1968 is attached to the memo.¹⁸ Based on this record, it appears the basis for operating the
13 section of Line 132 from MP 1 to MP 35.84 at an MAOP of 400 psig was a brief spike in Line
14 132 pressure to 400 psi in 1968.

15 PG&E originally tracked the Line 132 MAOP on a table that was Appendix A to
16 Standard Practice 463.8.¹⁹ In 1979, PG&E changed Appendix A to Drawing No. 086868.²⁰ In
17 more recent years, PG&E has maintained the content of this table in an excel worksheet, but the
18 final version is still maintained as Drawing 086868 (MAOP Drawing).²¹ From 1979 until 1987
19 PG&E was updating the table about every 2 years. There were no updates between 1987 and
20 1998. In 1992 another internal PG&E letter states that the table is supposed to be updated
21 annually and requests assistance in updating the MAOP data.²² Other PG&E internal
22 correspondence appears to show that updating this information lost priority within PG&E.²³

¹⁵ DR 30 Q 30 Supp Atch 2, p.102, SP463.8.

¹⁶ DR 30 Q 30 Supp Atch 3, p. 43.

¹⁷ By citing PG&E's certification based on the grandfather clause, CPSD does intend to imply that it agrees that a hydrotest was not required to establish the 400 psi MAOP for this section of L-132.

¹⁸ DR 30 Q 30 Supp Atch 3, p. 45.

¹⁹ P2-956 p. 6.

²⁰ P2-964.

²¹ Response to DR 39 Q 12.

²² Response to DR 30 Q 30 Atch 33, pp. 215 and 222.

²³ Response to DR 15 Q 1, including attachments.

1 Around 1997, updating Drawing 086868 prompted a series of actions that continued through
2 2010.²⁴ A list of Revision numbers and the changes made with each revision was kept from Rev.
3 14.1 through Rev. 20.²⁵ PG&E states that it did not retain any of the intermediate Revisions (i.e.,
4 15.1-15.9, 16.1-16.5, 17.1-17.19, and 18.1-18.5), including 15.4, which is on the list of revision
5 numbers with the notation: “Updated Line 132 MAOP to 400 psig, RTA 12/10/03 in handwriting
6 that matches the note found on the historical MAOP log that was edited.”²⁶

7 PG&E did not file a request with the CPUC to uprate the MAOP of the second section of
8 Line 132 from 390 psi to 400 psi.²⁷ It appears that, by 2003, the underlying records that define
9 the historical identification of two sections of Line 132 had been lost. The 2003 statements refer
10 to Line 132 as if the same MAOP should apply to the entire line. When PG&E was asked why
11 the Pipeline Survey Sheets showed an MAOP of 390 psig, it responded:

12 “Pursuant to 49 C.F.R. § 192.619, the MAOP on Line 132 was established
13 at 400 psig based on pressure records maintained by the San Jose Division
14 during the period between July 1, 1965 and July 1, 1970.
15

16 The design pressure of 400 psig on Line 132 is based on these records and
17 the Company has used that MAOP since at least 1975. During the
18 establishment of the initial MAOP documentation in the mid 1970s, in
19 accordance with CFR 192.619(3), San Francisco Division personnel
20 incorrectly identified the highest pressure at which the line operated as
21 390 psig, which was reflected on the PLSS. Records were later corrected
22 to match the 400 psig operating pressure which was the maximum that this
23 line operated at during the 1965-1970 period.”²⁸

24 Neither the above explanation nor the 2003 hand-written correction to the MAOP log agrees
25 with the history detailed in Appendix 1 of this testimony, in particular because both ignore the
26 historical distinction that PG&E had been made between the two sections of the pipeline. The
27 Pipeline Survey Sheets and the other records discussed above identify the MAOP for the section of
28 pipeline between Mile Posts 35.84 and 46.59 (which includes Segment 180) as 390 psi, not 400 psi.
29 However, in 2003, PG&E reset the MAOP for Line 132 between Mile Posts 35.84 and 46.59 and at

²⁴ Response to DR 30 Q 30 Atch 85 (example).

²⁵ Response to DR 5 Q 9, Atch 8.

²⁶ Response to DR 5 Q 9, Atch 8.

²⁷ Response to DR 7 Q15, which requests copies of all uprating requests submitted to the PUC does not include an uprating request for L-132.

²⁸ Response to DR 3 Q 20.

1 some time, either then or later, entered notes on historical documents to record the change. All of
2 the MAOP tables (Drawing 086868) and records PG&E has produced in this proceeding reflect 390
3 psi MAOP from 1978 to 2003 for the section of Line 132.

Deleted: Although PG&E states that it has been operating both sections of the line at an MAOP of 400 psi since at least 1975, there is no contemporaneous record of that MAOP.

4 Records explaining the downgrading of the MAOP to 390 psi between MP 35.84 and MP
5 46.59 have not been produced. PG&E should have validated the MAOP before changing it, but
6 there is no record indicating that it did so. Further, PG&E relied on 1968 records to make the 2003
7 “correction,” increasing the MAOP from 390 to 400 psi. Even if PG&E could show that the MAOP
8 of 390 psi reflected in its records was simply a mistake, the fact that the mistake persisted in
9 PG&E’s operating records, viewed daily by operating and engineering personnel for 25 years (until
10 2003), and then continued to persist until 2010 on some PG&E records after the mistake was
11 identified, is in itself a testament to PG&E’s poor recordkeeping practices.

12 In summary, the MAOP records for Line 132 are incomplete. Despite the continued
13 assertion that it had been operating the line at 400 psi, there are several contemporaneous and
14 chronological records documenting 390 psi for the section between Mile Posts 35.84 and 46.59..
15 PG&E’s subsequent, handwritten edits to these records to support the 2003 change to the historical
16 record or to support abandoning the lower MAOP for the section of Line 132 between Mile Posts
17 35.84 and 46.59 establish why PG&E’s poor recordkeeping was an unsafe business practice.

18 **2.3 Deficiencies in Clearance Recordkeeping**

19 PG&E failed to follow its records procedures, called the “clearance process,” for
20 planning the September 9, 2010 work at Milpitas Terminal. The clearance process is PG&E’s
21 detailed procedure for maintenance projects that can potentially disrupt service.²⁹ The work
22 procedure provides very specific instructions designed to lead operating and maintenance
23 personnel through a project in a way that will ensure the safety of the worker, the plant and the
24 public. The procedure requires extremely detailed documentation to be recorded and accessed
25 electronically, and also reproduced and filed in hard copy. Clearance communications and
26 required records are to be documented in PG&E’s electronic Clearance SharePoint system.³⁰ For
27 the uninterruptible power supply project that started on September 9, 2010, PG&E did not follow
28 its own clearance procedures.³¹

²⁹ P2-314, Utility Work Procedure WP4100-10.

³⁰ SharePoint is a Microsoft product marketed to businesses to allow people within a company to share information, manage documents from start to finish, and to publish reports. PG&E uses SharePoint to draft, coordinate and finalize policies, standard procedures as well as documenting clearances for work on

1 The clearance application was initially submitted in the computer system for approval on
2 August 27, 2010. This clearance application, required for Milpitas Terminal maintenance work
3 on September 9, 2010, was substantially incomplete, leaving the maintenance crew and control
4 room operators without the required step-by-step plan for the work they were doing.³² In
5 response to a data request, PG&E provided a copy of the clearance filed after September 9th to
6 complete the work on the uninterruptible power supply that was left unfinished on September 9th.
7 This later clearance follows PG&E procedures and shows what the original clearance records
8 should have looked like. For comparison, copies of both clearances are provided as Appendices
9 2 and 3 to this report.³³

10 If PG&E personnel had followed the clearance procedure, there would have been a step-
11 by-step plan put in place before the September 9, 2010 work at Milpitas began. Drawings would
12 have been readily available to the maintenance crew doing the work and to Gas Control
13 personnel who were attempting to help once problems arose. PG&E's clearance procedure is an
14 important record system designed to ensure the safety of employees and the public when work is
15 being done to the operating system. PG&E's apparent failure to require strict adherence to this
16 safety procedure is an important record system failure.

17 **2.4 Out-of-date Operating and Maintenance Instructions for Milpitas Terminal**

gas facilities. References to SharePoint were found in other documents. See P2-7, page 9, Section 6.7 and P2-670, p. 3, Sec 3.1.3.

³¹ P2-314 and P3-10034, PG&E Utility Work Procedure WP4100-10, Attachment 1 to WP4100-10 is the Control Room Clearance Procedure, which defines the roles and responsibilities, required processes, communication tools and methods, and documentation required for a gas work clearance.

³² Response to DR 37 Q1, A Clearance is a plan to do work that is submitted within the PG&E system to make sure everyone involved is aware of the work being done on the gas system while it is operating, knows when the work begins and when it is completed. The plan is essential to safe operations. For instance, when an application for a clearance is completed on the SharePoint system, a clearance supervisor must be identified. The partial application for September 9th shows the clearance supervisor as "TBA," or to be assigned. Apparently a clearance supervisor was never assigned. The Clearance Supervisor is responsible for and manages the clearance. Clearance Supervisors must be qualified to perform the clearance procedure and equipment they Report On be knowledgeable of clearance points and have the ability to ensure that equipment is cleared safely The Clearance Supervisor is the first person to Report On and the last person to Report Off for any clearance The Clearance Supervisor is responsible for all clearance logs Clearance Communications Board documentation and tagging.

³³ Response to DR 47 Q 4 Attachment 1 (September 9, 2010) and Response to DR 47 Q 11 Attachment 3 (October 2010).

1 The Operating and Maintenance Instructions manual at the Milpitas Terminal was out of
2 date on September 9, 2010, possibly by as much as 19 years, which would make it a useless
3 reference when the emergency occurred.

4 When PG&E schedules work to be performed on its electrical system, especially on a
5 system that powers pipeline instrumentation such as automatic and control valves and the data
6 transmission system, it is essential both to have competent and knowledgeable personnel doing
7 the work, and for those personnel to have all of the relevant maps, drawings, and manuals at
8 hand before beginning the work. All of those records must be up-to-date, so that they accurately
9 reflect the system as it exists on the day of the project. PG&E states that it does not know
10 whether the latest Operating and Maintenance (O&M) Instructions manual was at the Milpitas
11 Terminal on September 9, 2010 and is unable to verify what version of the manual was there.³⁴

12 PG&E explains as follows:

13 “PG&E confirmed that each of these facilities contains a hard
14 copy version of the Operating and Maintenance Instructions
15 applicable to that station, although not all 11 contained the most
16 recent revision. It is not possible to ascertain whether the version
17 contained at a station as of July/August 2011 was the exact
18 version that existed on September 9, 2010, and in several
19 instances new revisions of Operating and Maintenance
20 Instructions have been issued since that time. PG&E personnel
21 who operate and maintain unmanned major facilities have access
22 to the Company intranet, where the latest version of the relevant
23 policies and procedures exist.”³⁵

24 During this investigation, PG&E produced a copy of Operating and Maintenance
25 Instructions for Milpitas Terminal, Revision 6 (2009) and in the I.11-02-019 proceeding, PG&E
26 produced Revision 7 (2011).³⁶ When asked, PG&E failed to produce a copy of the O&M manual
27 that was at the Milpitas Terminal on September 9, 2010, but it listed a 1991 manual in a
28 Summary Inventory of Milpitas documents.³⁷ PG&E did not produce a copy of the 1991 manual
29 for review. Failing to provide updated Operating and Maintenance Instructions over the course of
30 many years reflects a deficiency in an important area of documents and records.

³⁴ Response to DR1 Q1b Supp 02, p. 19 (note: Milpitas is an unmanned facility.).

³⁵ Response to DR1 Q1b Supp 02, p. 19.

³⁶ Rev 6: Response to DR 1 Q1b, Attachment 42 (file mislabeled by PG&E as DR1-Q0(42)) and Rev 7:
Response to CPSD 242 Q2, Attachment 1.

³⁷ Response to DR 1 Q 7, Attachment 2. p. 3.

1 **2.5 Out-of-date Drawing and Diagram of the Milpitas Terminal**

2 On September 9, 2010, PG&E personnel at the Milpitas Terminal may have been
3 working with an outdated map and control room personnel may have been working with an
4 incomplete diagram of the Milpitas terminal.

5 When trying to control the pressure by manually opening or closing valves, PG&E
6 personnel needed access to current and accurate drawings. If the personnel at the Milpitas
7 Terminal were referring to the piping and instrumentation drawing available at the Milpitas
8 Terminal during that crisis, they may have been using a drawing that was incorrect.³⁸ In
9 response to a data request, PG&E verified that drawing #383510, which it submitted to the
10 NTSB, had been corrected after September 9, 2010 to accurately reflect the terminal design on
11 that date. Thus, the drawing available to the personnel at Milpitas Terminal on September 9,
12 2010 did not accurately reflect the then current terminal design. In addition, the diagram for the
13 Milpitas Terminal that was used by San Francisco Control Room operators was inaccurate and
14 incomplete. The diagram has been revised three times since the San Bruno incident.³⁹ On
15 September 9, 2010 the diagram at the Control Room was apparently missing a bypass line
16 outside of the Milpitas Terminal fence line. This appears to be a significant inaccuracy in the
17 diagram because, during the emergency, PG&E personnel were attempting to control
18 high-pressure gas that they thought might be by-passing the Terminal.^{40 41}

19 “On October 27, 2010, existing valves and piping related to the
20 bypass system were added to the SCADA Milpitas Terminal
21 operating diagram to provide Gas System Operators additional
22 visibility of the bypass line configuration outside the Milpitas
23 Terminal fence line. The valves that were added to the diagram
24 were V-0.11, V-0.12, V-0.13, V-30, V-31, V-32, V-57.45, V-300,
25 V-400, V-401, V-500, V-502.12A, V-600 and V-602, along with
26 the associated piping . . .”⁴²
27

28 Based on the San Francisco Control Room transcripts for September 9, 2010, it seems
29 there was confusion between the person at the Milpitas Terminal and the Control Room Operator

³⁸ Response to DR 3 Q 15.

³⁹ Response to DR 8 Q8.

⁴⁰ Transcripts

⁴¹ Response to DR 8 Q 8 (c).

⁴² Response to DR 8 Q 8 (c).

1 about valve numbers at the Milpitas Terminal.⁴³ At least some of the confusion experienced at
2 the Milpitas Terminal and the Control Room during the emergency appears to have been related
3 to inadequate reference documents.

4 **2.6 No Back-up Software at the Milpitas Terminal**

5 The first indication of a problem at the Milpitas Terminal was described by the PG&E
6 maintenance personnel on site as a loss of controllers. He clarified the situation in a subsequent
7 interview by stating that they lost the programming to 3 controllers. Despite PG&E's policy
8 quoted below to have a back-up of the software onsite, there was no backup at Milpitas on
9 September 9, 2010.

10 "The PLC system is located in the computer room in the Control
11 Build. . . . The 3 Ethernet Interface modules in each PLC rack
12 are to provide communication with the Process Automation
13 Controllers (PAC). Only the modules in the PLC, which is in
14 control (Master or Slave), are communicating with the PAC
15 controllers.
16

17 The 2 serial Communication Coprocessor modules in each PLC
18 rack are used to provide serial communication interfaces between
19 the PLC and the local HMI and the PLC and SCADA terminal in
20 Gas Control. . . .
21

22 The PLC may be accessed via programming terminal in the
23 computer room or any PC with the GE VersaPro software. *Copies
24 of the program are kept on the hard disk of the programming
25 terminal and the back-up copies of the programs must be kept on a
26 floppy diskette at the Terminal. A hard copy is available at the
27 terminal.*⁴⁴ (italics added)

28 In theory, the maintenance person at the terminal could have reloaded the software from
29 his laptop. However, his software was not compatible with the model number of the three
30 controllers that lost programming.⁴⁵ An engineer had to be called in to bring the software on his

⁴³ Response to DR 8 Q 8 c. ant DR 8 Q 8 Attachment 3.

⁴⁴ Response to DR1 Q 1b, Attachment 42, Milpitas Terminal Operations and Maintenance Manual, Rev. 6, p. 77-78, 2009.

⁴⁵ SF Control Room Transcript Line 11.03.33 PM - .wav file 6079390000394346 ". . . I'll give you a call once [the engineer] starts reloading the programs in there. . . . I don't have the software for the 353s. I got all the stuff for the 352s but these are the 363s." and OM transcript, Sept 16, 2010, p. 29 lines 2-4: "My laptop only has a program for the 352 Moore controllers. These are 353 controllers, so I did not have the programming, the software for them." (Note: It is unclear whether the controllers at Milpitas Terminal are 353 or 363 Moore controllers since both are stated here).

1 laptop computer.⁴⁶ The engineer arrived at the Milpitas Terminal several hours later and restored
2 the system at midnight, long after 5:20 p.m., when controllers system had failed.⁴⁷

3 When PG&E was asked whether employees regularly keep records on their personal
4 electronic devices, the response was:

5 “Many PG&E employees have access to numerous electronic
6 copies of technical or engineering records through their laptops or
7 personal electronic devices. Although most electronic records are
8 stored on the company servers, electronic records may
9 occasionally be stored on employees’ laptops or personal
10 electronic devices.⁴⁸

11 Even though there may be some instances in which software may be safely carried by
12 maintenance personnel and engineers for job convenience, it is clearly an unsafe and poor
13 engineering practice for PG&E’s only copy of critical software to be on a laptop stored remotely
14 from the programmed equipment.

15 **2.7 The Supervisory Control and Data Acquisition – Electronic Recordkeeping**

16 The data transmission collection and display system for PG&E’s gas transmission system
17 is referred to as Supervisory Control And Data Acquisition (SCADA). The SCADA system
18 provides data to the control rooms. On September 9, 2010, San Francisco Control Room
19 operators were alerted by “Hi-Hi” alarms from instruments at the Milpitas Terminal and along
20 the Peninsula pipelines indicating high pressures. The control room policy is to acknowledge all
21 alarms and then the operator has 10 minutes to analyze the problem and respond to the alarm.⁴⁹
22 On September 9, 2010, after controllers were lost and pressure went out of control at the Milpitas
23 Station, many alarms went unacknowledged and repeated regularly, creating long screens of
24 repeating alarms.⁵⁰

25 A few minutes after the pipeline in San Bruno ruptured, there was a “Low-Low” alarm
26 that came in from Martin Station at 6:15 PM. This alarm was an indication of the San Bruno

⁴⁶ SF Control Room Transcript Line 9.9.2010- 10.58.38- PM - 607939000394344- 0001: [Name]: “We’re waiting for <Unintelligible> [name] the engineer to show up, we’re gonna load all the programs back in it because we lost the programs on it.”

⁴⁷ SF Control Room Transcript Line 11:57:23 PM - .wav file 6079390000394367 “. . . Because those are the ones that weren’t controlling those, those few and (name) just now got them working.”

⁴⁸ Response to DR 1 Q 10.

⁴⁹ Response to DR 1 Q 12, Attachment 154, p. 5.

⁵⁰ Response to DR 1 Q 14, Attachment 2.

1 pipe failure. Control room operators failed to acknowledge the alarm and did not recognize the
2 drop in pressure until almost 30 minutes later, when someone from another location called in and
3 asked them to look for the pressure drop on their SCADA screens.⁵¹ In fact, even after they
4 found the pressure drop, they could not identify the location of the pipe failure using SCADA
5 data.⁵²

6 There were no remote control valves installed in Line 132 at the time of the pipe failure
7 because PG&E had decided that they were not warranted. PG&E assumed that the damage from
8 a broken line would occur before the valves closed automatically.⁵³ In fact, control room
9 operators did not know if there were any valves that could be used to shut off the gas.⁵⁴ Because
10 the control room operators failed to detect the pipe failure and were unable to immediately
11 determine its exact location and were unfamiliar with the location of valves, they could not
12 provide useful information to field personnel and managers. Such information might have been
13 helpful in reducing the amount of damage that occurred by shortening the one hour and 35
14 minutes it took PG&E to shut off the gas.

15 **2.8. Emergency Response Plans Too Difficult to Use**

16 PG&E's Emergency Response Plans were difficult to use and were a source of confusion
17 for the Control Room operators, probably contributing to PG&E's inability to mount a credible
18 response to the incident on the evening of September 9, 2010. PG&E's emergency plan is very
19 complex and was apparently difficult for personnel to implement during the San Bruno
20 emergency.⁵⁵ The summary reference pages for personnel to refer to are shown in
21 Figures 1 and 2.

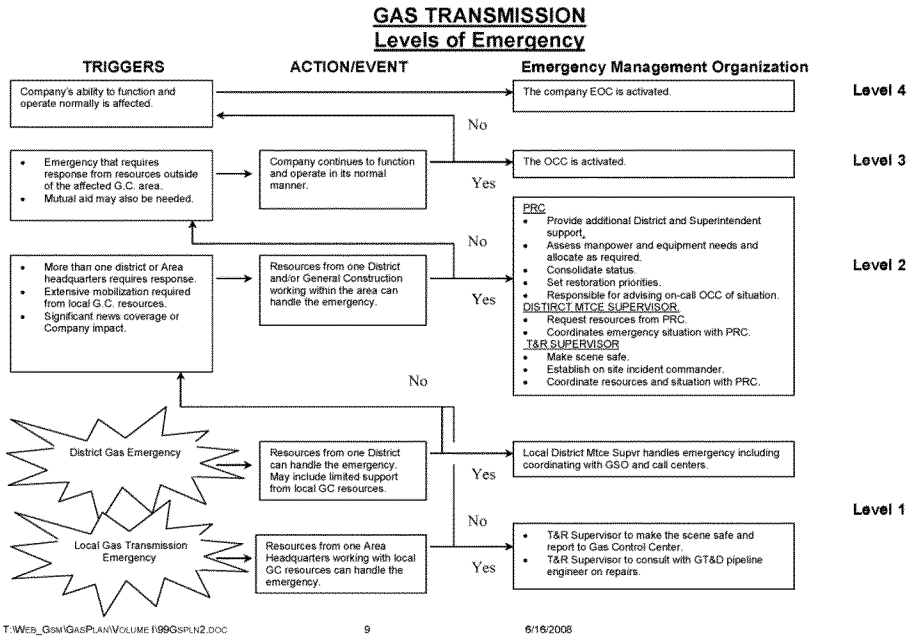
⁵¹ Response to DR 1 Q 14, Attachment 2 , see highlight at 18:15 PM

⁵² Response to DR 30 Q 21 Interviews of PG&E Employees conducted by the NTSB Interview September 16, 2010, Interview of MV, p. 25: ““We knew . . . as we were pulling maps and diagrams and laying them out on the table that it was a line break. But . . . it wasn't confirmed until we got a call from the field engineer.”

⁵³ P3-30154 p. 16 (NSEG 132 2004 Long Term Integrity Management Plan, approved 4/26/2010).

⁵⁴ Transcript_Excerpt_Valves_Between_stations

⁵⁵ SF Control Room transcript.



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Figure 1

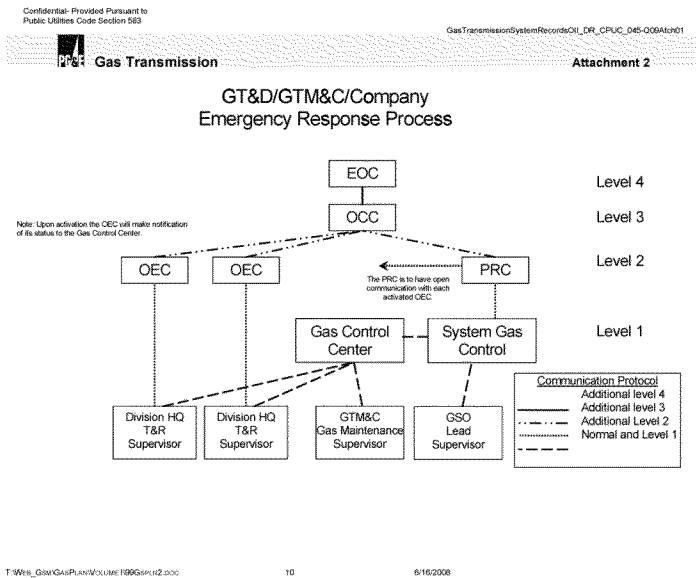
On the transcript of the audio recording made in the San Francisco Control Room during the emergency, it is clear that there was confusion about the emergency response plan.⁵⁶ Studying Figure 1, which is supposed to be the short-hand guide to responding to an emergency, confirms that the confusion was warranted. For example, it is not clear who in PG&E was supposed to be in charge of the response to the San Bruno incident, a level 4 emergency.⁵⁷

Emergency response plans are useful only if they are written and implemented in a way that makes the information immediately accessible and easy to understand and to follow in situations when events are overwhelming. The plans must be updated regularly so an employee or contractor will not rely on obsolete information or call invalid phone numbers to reach key personnel. The complexity of PG&E's Emergency Response plan can be seen in the flow chart it

⁵⁶ SF Control Room Transcript: excerpt_ER_Confusion.

⁵⁷ The trigger for Level 4, as described on the diagram, is "Company's ability to function and operate normally is affected."

1 provides to its employees.⁵⁸ (Figure 2) Each center referenced is opened by a predefined
 2 manager within PG&E.⁵⁹ “EOC” is the Corporate Emergency Operations Center. “OOC” is the
 3 Operations Coordination Center. “OEC” is the Operations Emergency Center and “PRC” is the
 4 Pipeline Restoration Center. Not shown on the diagram, but referenced in the Company-wide
 5 Gas Emergency Response Plan is the “CCECC,” or Call Center Emergency Coordination
 6 Center.⁶⁰



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Figure 2

9 PG&E describes its emergency response guidance as follows:

10 “As of September 9, 2010, there were three sources of emergency
 11 procedures that PG&E maintained that applied to transmission line
 12 incidents, including incidents that occurred at Stations and System
 13 Gas Control facilities within PG&E’s transmission system. First,
 14 PG&E maintained a Company-wide Gas Emergency Plan. This
 15 plan is utilized throughout the Company and the gas organization.
 16 Second, each of PG&E’s 17 divisions maintains a Gas Emergency
 17 Plan. The Division Emergency Plans contain substantially the
 18 same substantive information. The differences between division

⁵⁸ Response to DR 45 Q 9, Attachment 1.

⁵⁹ Per the Company-wide Gas Emergency Plan.

⁶⁰ Per the Company-wide Gas Emergency Plan, Part 1, p. 35.

1 plans primarily relate to emergency contact information, which is
2 unique to each division. Third, gas transmission districts also
3 utilize the GT&D and GTM&C Emergency Plan Manual. It
4 consists of two volumes. Volume One describes the emergency
5 plans of Gas Transmission & Distribution (GT&D) and Gas
6 Transmission Maintenance & Construction (GTM&C) and how
7 they integrate with PG&E's emergency management organization.
8 Volume Two provides guidance to field personnel responding to
9 an emergency. The guidance includes phone contacts for support
10 services, emergency pipe stock inventories, and emergency
11 response check lists.

12
13 All of the Emergency Plans and Manuals are accessed by PG&E
14 employees online through the Gas Transmission document library.
15 The online versions of the Plans and Manuals contain a table of
16 contents with hyperlinks to each individual document contained
17 therein.”⁶¹

18 PG&E's manuals are difficult to follow and some sections appear to be out of date, still
19 referring to the previous organizational structure in which the main control room was in
20 Brentwood and a supervisory function was in San Francisco.⁶² The unwieldy length of these
21 documents presents a potential problem for functionality. The company-wide gas emergency
22 plan is 536 pages long. The CGT Emergency Plan is 347 pages and the Peninsula Division Plan
23 is 688 pages.⁶³ The plans provided were dated 2008. Operating a safe gas transmission system
24 requires emergency plans that can be readily understood and followed in an emergency.

25 **3.0 RECORDKEEPING ISSUES HAVE HISTORICALLY CREATED**
26 **DEFICIENCIES IN PG&E'S INTEGRITY MANAGEMENT EFFORTS**

27 The purpose of this section is to take a critical look at the implications PG&E's poor
28 recordkeeping practices have for its gas transmission system and its integrity management
29 program risk ranking models. Virtually all of the records required to create accurate and useful
30 risk program models that are discussed below are records that were required to be kept for the
31 life of the facility and, in some instances, for the life of the facility plus 6 years.⁶⁴

⁶¹ Response to DR 1 Q 8.

⁶² Response to DR 47 Q 25: PG&E began using the San Francisco control room as the sole main control room, with Brentwood as the back-up, on April 4, 2010.

⁶³ Response to DR 1 Q 8, p. 38 (PG&E provided emergency response plans one page at a time): CGT Emergency Plan, 341 pages, Company Wide Gas Emergency Response Plan, 536 pages, and the Peninsula Division Emergency Plan, 688 pages.

⁶⁴ Response to DR 9 Q1, PG&E acknowledges this requirement in the revised Table 2A-3. The Table is

1 The Transmission Integrity Management Program (TIMP) regulations effective in 2004
2 require operators to take specific steps to manage risk in natural gas pipeline systems. PG&E's
3 current integrity management program has at its core a risk assessment model that it began
4 building in 1984 as part of its Gas Pipeline Replacement Program (GPRP).⁶⁵ The scale of
5 PG&E's current model is much larger than the initial 1984 model because PG&E has included
6 more data fields and pipeline segments. However, the underlying concept is the same, i.e.,
7 PG&E defines risk as the product of the likelihood of failure times the consequence of that
8 failure (LOF X COF) and the basic structure of the model is the same as it was in 1984.

9 **3.1 Records of Pre-1984 Pipeline Replacement at PG&E**

10 PG&E cannot cite to any specific program prior to the 1980's to inspect its pipelines and
11 plan for orderly replacement. In its June 20, 2011 filing PG&E states: "[i]t is not possible to
12 identify and accurately summarize every pipe replacement job done these many years ago that
13 was or may have been based on a written safety risk assessment."⁶⁶ And, PG&E says it sought to
14 reduce risk on its gas transmission system principally through pipeline specific analyses and
15 projects.⁶⁷ PG&E points to numerous examples of individual pipeline replacement projects
16 where pipe was replaced for integrity-related reasons, primarily leaks caused by corrosion.⁶⁸
17 Upon review of these records, it is clear that PG&E's approach to pipe replacement was to wait
18 until a pipe had so many leaks that it was no longer feasible to add one more repair. The
19 following examples illustrate PG&E's approach into the 1970's.

- 20 • 38 Leaks: "The above sections of main were installed bare 38 years ago with a
21 MOP of 500 psi and traversed grazing and dry farming land with a high soil
22 resistivity. As irrigation increased in the area pipe corrosion increased causing 38
23 leak repairs."⁶⁹
- 24 • 97 Patches: There are 19 street patches each representing an excavation, for the
25 purpose of repairing leaks. . . that have been made over a period of six years,
26 most of them in 1959 and 1960. In each hole, the pipe was found to be badly
27 pitted and corroded (wall thickness being reduced up to 40% of its original
28

provided in this report as Appendix 4.

⁶⁵ P3-20024, p. 13.

⁶⁶ PG&E Report, June 20, 2011, Page 6C-3 lines 16-26.

⁶⁷ Response to DR 1 Q 16, Supp 1. p. 3.

⁶⁸ PG&E Report, June 20, 2011, Page 6C-3 lines 16-26.

⁶⁹ P3-27424, Proposal to replace two sections of 26" StanPac Line No. 2, 1969.

1 thickness). Areas as large as 14” in diameter were found where pipe thickness
2 was greatly reduced. A total of 97 patches were welded onto the pipe in the 19
3 excavations. A number of the patches cover actual leaks while others cover deep
4 pits and corroded areas. Innumerable spots were found where the wrapping was
5 separated from the pipe and formed pockets which impounded water. The
6 longitudinal seam is pitted along each side of the weld making it especially
7 susceptible to leaks. One stretch of seam had to be repaired with a 5’ long half
8 sole. The seam was in such bad condition that real concern was felt about the
9 possibility of its splitting open while the crew was working on it.”⁷⁰

- 11 • 23 Leaks: “The existing line is bare pipe and has had an increasing leakage
12 history. It has had a total of 23 leaks. Fifteen leaks have occurred since 1960, five
13 of which occurred in 1970.”⁷¹
- 14 • Still Leaking: “In answer to complaints of gas odor’s the main was bar tested [a
15 bar of wet soap is rubbed over the pipe to spot bubbling where gas is leaking].
16 The main was exposed at 7 locations and 3 temporary clamps, 2 welding patches
17 and 2 half soles installed. Visual inspection of approx. 30 feet of this single
18 wrapped main revealed heavy pitting. . . . A recent bar test, at 50 ft. intervals
19 reveals leakage still persists over the entire area to be replaced. It is no longer
20 practical to maintain this 46 year old main”⁷²
- 21 • 1 Leak every 3.6 feet: “The City of Oakland had planned to resurface Livingston
22 Street . . . [t]he repaving is by the heater-planer remix process which cannot be
23 used until the gas indications at the surface are eliminated. Line 105 was recently
24 bar tested and (35) indications were recorded on (94) locations tested. . . . Past
25 repairs from 1948 to 1969 indicate (125) welded patches, (576) spot, and (10)
26 circular bands. Twenty-nine percent of the proposed replacement length has had
27 some type of welded repair, averaging (1) every 3.6 feet.”⁷³

28
29
30 These examples are provided to show that PG&E was primarily reactive to leaky lines, not
31 proactive in planning to replace lines before they posed a safety risk. These examples also
32 demonstrate that PG&E has records of early pipeline leaks and failures and that PG&E was aware
33 that there could be many leaks on some sections of lines.

34 **3.2 Forward Planning For Pipeline Replacement – Records Issues**

35 In 1984, a forward-looking, 30 year plan, called the Gas Pipeline Replacement Plan
36 (GPRP), was proposed within PG&E:

⁷⁰ P3-27430 Proposal to replace part of 20” pipe, Line 101, 1960.

⁷¹ P3-27432 Proposal to replace 26” pipe, Stanpac Line No. 2, 1972.

⁷² P3-27435 Proposal to replace 8” main, San Rafael, 1970.

⁷³ P3-27438 Proposal to replace 20” line, Oakland, 1971.

1 “The steel transmission lines proposed for replacement are 38 to 55 years
2 old and were originally installed in open spaces, often in narrow rights-of-
3 way in areas which have since been highly developed. Many of these
4 pipelines are now in confined areas with reduced ground cover. They
5 need to be replaced with modern pipe to enable PG&E to continue to
6 provide safe and reliable service. In addition, the three pipelines
7 supplying San Francisco from Milpitas were built between 1929 and 1947
8 also. They will be replaced with pipelines capable of operating at higher
9 pressures, which will provide sufficient pipeline storage to allow
10 abandonment of the remaining aboveground low-pressure gas holder in
11 San Francisco.”⁷⁴

12 In parallel to the proposed GPRP to replace whole pipelines, PG&E contracted with
13 Bechtel in 1983 to use risk analysis to assist PG&E in identifying pipe that should be replaced.⁷⁵
14 By 1984, Bechtel developed a replacement priority analysis and database to rank the order in
15 which segments of gas transmission lines and distribution mains should be considered for
16 replacement under the program.⁷⁶ The concept proposed by Bechtel was to use probability
17 analysis to predict the segments that posed the highest risk.⁷⁷ Theoretically, the higher the risk
18 number calculated for a pipe segment, the more likely it is to fail and cause significant injury to
19 people and property. Those segments with the highest risk numbers rise to the top of the list for
20 repair or replacement. Bechtel and PG&E continued to refine the model over the next 20 years.
21 This model was integrated into PG&E’s GPRP program and was the precursor to the current
22 PG&E Integrity Management Risk Assessment model.

23 In its 1990 Annual Progress Report on GPRP PG&E stated that by replacing higher
24 priority pipe first, emphasis is focused on maintaining a safe operating system in the most cost-
25 effective manner.⁷⁸ What PG&E did *not* say in its report was that it did not have adequate
26 historical data about its pipeline system to populate the required data fields in a risk assessment
27 model so it would produce accurate and useful results.

⁷⁴ Response to DR 44 Q 1(a), Attachment 30, p. 3.

⁷⁵ Response to DR 44 Q 1 (a) Attachment 29.

⁷⁶ Bechtel Report, 1984.

⁷⁷ Bechtel Report, 1984.

⁷⁸ P3-20024, 1990 Annual Progress Report on PG&Es GPRP, Work was funded in the 1987 GRC,
(D.86-12-095).

1 In 1985, when the initial risk assessment model was ready to be populated with real data,
2 PG&E issued a memo that included a long list of required data and requested assistance.⁷⁹

3 "We have now received the data base computer printouts for all Divisions.
4 A copy of this data base for your Division is enclosed. You will note that
5 there are still some areas with missing data. These areas are marked in
6 yellow on the enclosed computer printout. Before we run the risk
7 analysis, we would like to complete the data base as much as possible.
8 Therefore, we ask if your staff would provide any missing information
9 based on the knowledge of Division personnel or retired employees with
10 whom you have maintained contact."⁸⁰

11 As discussed in section 4.0 of this testimony, PG&E has not been able to find much of this
12 historical data.

13 Despite the lack of data, PG&E and Bechtel continued to develop the risk assessment
14 model. The discussion below highlights how the relative importance of data changed over time,
15 perhaps due to the lack of certain types of data. And, in some instances, assumptions were made
16 to overcome the lack of actual data. Bechtel assigned the following weighting to variables in its
17 1984 Risk Analysis model:

- 18 • Pipe segment Age: 40%
- 19 • leak history: 15%
- 20 • weld types 10%
- 21 • pressure test type 10%
- 22 • coating type 4%
- 23 • pipe quality and future performance (anticipated future problems in the event of
24 operating changes) 1%⁸¹

25 Pipe Age: The Bechtel model used the date of installation to calculate the age of
26 the pipe. For this variable, an inaccuracy arises in some instances, but cannot be
27 specifically identified, because the installed locations of re-used pipe within PG&E's gas
28 transmission system are unknown. Thus, installation date may not accurately reflect the
29 actual age of the pipe.

⁷⁹ Response to DR 44 Q 1(a) Attachment 33.

⁸⁰ Response to DR 44 Q 1(a) Attachment 33.

⁸¹ 1984 Bechtel Report, p. 9.

1 Leak History: Bechtel reported that PG&E’s engineers expressed little confidence in the
2 accuracy of leak data, believing the leak history was under-recorded. Bechtel states that its
3 experience is that the number of leaks experienced by any given transmission line segment rarely
4 exceeds two and uses this assumption in the model.⁸² However, PG&E’s job file records show
5 many segments with many more than two leaks.⁸³ So, for assessing PG&E’s pipelines, Bechtel’s
6 assumptions about low numbers of leaks in PG&E’s pipes proved to be incorrect. (Yet, the same
7 assumption exists in its TIMP model today.) In 1994 PG&E begins stating in its reports that it
8 began keeping leak records in 1971.⁸⁴ PG&E collected leak data on A-Forms, also known as
9 Form 62-4637, much earlier than 1971, but failed to keep it in an accessible manner.⁸⁵

10 Weld Type: Bechtel included only girth welds in this category. The assignment of points
11 implies gas welds are five times more likely to fail than arc welds: Oxy-Acetylene Gas Welds
12 (10 points) and Electric Arc Welds (2 points). Thus, there is an assumption that PG&E knows
13 the history of the installation of the pipeline segments.

14 Pressure Test Type: Three types of pressure tests are considered: leak test, gas test and
15 hydro test. The logic is that a poorly executed weld is more likely to go unnoticed if a leak test
16 was performed under pressures well below operating pressures (leak tests) than if a gas or hydro
17 test had been performed. PG&E is in the process of searching its records in a multi-year effort to
18 produce traceable and verifiable records to support the maximum allowable operating pressures
19 it has assigned to its transmission lines. Its search immediately revealed incomplete pressure test
20 records. In addition, some GIS records PG&E has located cannot be confirmed through
21 supporting documentation and therefore are unreliable. For instance, the GIS entry for a gas test
22 for Segment 180 is “Gas” in 1961, but PG&E has not located any supporting documentation for
23 that entry.⁸⁶

24 Coating Type: The type of coating on a pipe is directly related to protection against
25 corrosion. According to Bechtel, “[t]he problem encountered in using this data variable . . . stems

⁸² 1984 Bechtel Report p. 11.

⁸³ See list examples listed above in this report. Also based on the authors review of thousands of PG&E’s documents in the ECTS database.

⁸⁴ P3-20038 p. 18.

⁸⁵ P3-10005(b), p. 118 and also from author’s review of PG&E records in the course of preparing this testimony.

⁸⁶ Response to DR 45 Q 8.

1 from the lack of confidence in the information pertaining to the coating type (58% confidence in
2 accuracy) and coating condition (46% confidence in accuracy).⁸⁷ The condition of coatings is
3 reported on PG&E's A-Form each time a pipe is uncovered for a construction project, testing,
4 repair, or inspection. A-Forms are not well organized, are incomplete and are difficult to read.
5 As discussed earlier, PG&E lacks confidence in this data and its concern is justified.

6 Pipe quality and future performance: The remaining 1% was given to pipe quality and
7 future performance, also stated as "anticipated future problems in the event of operating
8 changes" which were apparently considered unimportant. Bechtel assigned inconsequential
9 values to pipe type and longitudinal seam efficiencies on the basis that "PG&E's lines operate at
10 pressures that conform to G.O. 112 standards, therefore, risk of failure related to these
11 parameters is low." In other words, Bechtel assumed PG&E knew the nature and quality of pipe
12 and pipe welds throughout its system and that it had always operated pipelines at the appropriate
13 pressures based on this knowledge. That assumption cannot be validated because PG&E does
14 not keep pressure operating data for the life of its facilities.

15 While Bechtel's early work to develop the GPRP prioritization model was underway,
16 PG&E replaced Line 101 and planned to replace all of Lines 109 and 132.

17 "In 1985 Pacific Gas and Electric Company implemented the Gas
18 Pipeline Replacement Program (GPRP) to replace aging gas pipe
19 throughout the PG&E system. As part of this program, plans were
20 formulated to replace the three natural gas pipelines supplying San
21 Francisco from the gas terminal in Milpitas. These lines are 109,
22 132 and 101. The program called for replacing the gas lines with
23 higher quality pipe and for employing more advanced welding
24 techniques. The new pipelines would have lower leak frequencies
25 and higher operating pressures. The higher pressures would
26 provide sufficient pipeline storage to allow abandonment of the
27 above-ground, low-pressure gas holder in San Francisco.

28
29 The three pipelines, Lines 101, 109, and 132, were built between
30 1929 and 1947. Line 101 was replaced in 1985-1990 in order to
31 have one of the three pipelines fully replaced to meet current
32 standards. Line 109 and 132, [are] scheduled for start of
33 replacement in 1992 and 1999 respectively. . . ."⁸⁸

⁸⁷ 1984 Bechtel Report, p. 13.

⁸⁸ SB_HC_3972241 Gas Lines 132 and 109 Replacement Study, March 1991.

1 But, Lines 109 and 132 were never fully replaced as planned. Instead, these lines became
2 subject to priority assessment and presumably to the output of the risk assessment model – a
3 model lacking the data necessary to accurately identify the pipe segments that presented the
4 highest risk.

5 Bechtel’s 1995 Report, drafted for PG&E, titled Review of the Transmission Priority
6 Analysis (1994 Revision) for the Gas Pipeline Replacement & Rehabilitation Program, refers to
7 the risk assessment model as the “priority analysis and data base.”⁸⁹ The model is a later version
8 of the initial risk assessment model proposed in 1984. The priority analysis included
9 oxyacetylene girth welds, unshielded arc welds, bell and spigot joint types, narrow angle butt
10 welds and bell-bell, chill joint types. It specifically excluded all pipeline segments with
11 incomplete or unknown data and all pipeline segments installed after 1940, based on the theory
12 that later welds were made “utilizing modern arc welding techniques and joint configurations
13 that represent a relative low risk of failure and are not currently subject to replacement.”⁹⁰ Given
14 PG&E’s lack of weld records for its transmission lines, it is not clear what progress may have
15 been achieved by this addition of higher risk welds.⁹¹

16 **3.3 The 2004 Transmission Integrity Management Program - Records Issues**

17 PG&E is required to have a transmission integrity management program to track and assess
18 the integrity of its pipelines.⁹² The Transmission Integrity Management Program (TIMP)
19 requirements are relatively new, having been incorporated into Federal regulations in 2004. But
20 the underlying PG&E engineering responsibility to safely manage the integrity of its high
21 pressure pipelines is not new. PG&E has had this responsibility since it first started transporting
22 gas as a public utility, and perhaps before.⁹³ PG&E describes TIMP:

23 “PG&E implemented TIMP through its existing risk management
24 program. However, where its risk management program applies to
25 all of PG&E’s gas pipeline segments operating at a pressure
26 greater than 60 psi, TIMP applies to a subset of those segments

⁸⁹ P3-20038, Bechtel Report 1994 Revision, May 1995.

⁹⁰ P3-20038, Bechtel Report 1994 Revision, May 1995.

⁹¹ Further discussions regarding the lack of types of records are in Section 4.0 of this report.

⁹² 49 CFR Part 192, Subpart O: Subpart O requires all pipeline operators to implement a Transmission Integrity Management Program (TIMP) to assess and manage the integrity of all gas transmission pipelines in High Consequence Areas (HCAs).

⁹³ GO 112 and CFR 192 regulations, and Section 451 of the California Public Utilities Code.

1 meeting the definition of a “transmission line” in 49 CFR Section
2 192.3. Further, TIMP requires integrity assessments for those
3 segments operating within High Consequence Areas (CHAs),
4 roughly 20 percent of PG&E’s existing transmission pipeline
5 segments (or approximately 1,020 miles).⁹⁴

6 PG&E explained in its report how it continued to develop risk management models “to
7 supplement and improve operational processes related to managing system risks.”⁹⁵ It says it
8 initiated a Gas Transmission Risk Management Program in 1998.⁹⁶ The PG&E model should
9 have proved useful to PG&E in complying with 2004 Federal regulations. PG&E states:

10 “In brief summary, prior to 1985, PG&E sought to reduce risk on
11 its gas transmission system principally through pipeline-specific
12 analyses and projects. Beginning in 1985, PG&E consolidated
13 many of these activities into the Gas Pipeline Replacement
14 Program (GPRP), a programmatic initiative that was continually
15 refined. Since the late 1990s, PG&E has performed risk
16 assessments on its gas transmission pipelines through a Risk
17 Management Program that anticipated Integrity Management
18 regulations in 49 C.F.R. Part 192 Subpart O, which were
19 introduced in 2003. Under the Risk Management program, PG&E
20 utilizes its integrity management risk assessment model to evaluate
21 potential risks on transmission pipeline segments and to analyze
22 those segments to determine the most effective actions to reduce
23 that risk.”⁹⁷

24
25 Since 2004, PG&E has been developing a large integrity management risk assessment
26 model based on the original Bechtel model. It runs on a Microsoft Excel spreadsheet (in 2009
27 the size of the spreadsheet was 19,963 rows (pipe segments) by 342 columns (input data,
28 information and calculations).⁹⁸ The model is supported by many guidance documents, ongoing
29 field data collection mostly related to external corrosion, and constant system modeling and
30 report writing activities.⁹⁹ Under its risk management program, PG&E utilizes its integrity
31 management risk assessment model derived from the Bechtel model to evaluate potential risks

⁹⁴ Pursuant to Method 2 of the HCA designation criteria set forth in 49 CFR section 192.903; PG&E Report filed June 20, 2011, p. 6C-11.

⁹⁵ PG&E Report filed June 20, 2011, p. 6C-9.

⁹⁶ PG&E Report filed June 20, 2011, p. 6C-9.

⁹⁷ Response to DR 1 Q 16 Supp 1.

⁹⁸ P3-20060_1_thru_3(N)_CONFIDENTIAL.

⁹⁹ Response to DR 3 Q 7, a list of TIMP related documents.

1 on transmission pipeline segments and to analyze those segments to determine the most effective
2 actions to reduce that risk.¹⁰⁰ One output from the integrity management risk assessment model
3 is the annual “Top 100” pipeline segment list that, according to PG&E, presents the segments
4 with the highest risk of failure in the “discrete categories: the potential for external corrosion,
5 third-party damage, the physical design and characteristics of the segment, the potential for
6 ground movement, and the overall risk of the segment.”¹⁰¹ However, PG&E recently said that it
7 does not currently maintain a top 100 list. Instead, PG&E provided a combined list of the
8 segments included on the 2007, 2008, and 2009 top 100 lists for long-range evaluation and
9 planning to the CPUC on February 11, 2011, and updated the list on March 9, 2011.¹⁰²

10 PG&E stated that it uses the results of the risk model to prioritize and justify projects by
11 providing the risk score before a project is initiated and providing a predicted score for after the
12 work is completed, thereby showing the reduction in risk of failure as a result of performing the
13 repair or replacement project.¹⁰³ However, the effectiveness of this risk model is directly related
14 to the quality of the data used in the model and the quality of the data is suspect (in many
15 instances the data is assumed or missing). Therefore, using this model to prioritize projects
16 seems risky in itself because high risk projects may be overlooked.

17 While the number of documents produced from the integrity management program is
18 impressive, a review of the actual spreadsheet model reveals an unimpressive model that simply
19 adds up data entries and assigned points based on some simple calculations to arrive at a total
20 risk number for each segment. The combined lack of data, assumed, unknown values, and
21 questionable quality of the data entered into the model spreadsheet, suggests the model is of only
22 minimal practical use and is more likely entirely useless in calculating total risk. PG&E’s risk
23 modeling efforts have always suffered from a deficiency in basic historical data and its current
24 risk management model suffers from the same problem. As a result, the rankings generated from
25 the model cannot be an accurate representation of the real likelihood of failure of segments. The

¹⁰⁰ Response to DR 1 Q 16, Supp01, Note: this statement assumes the risk assessment model contains complete and accurate data, which is not the case to date.

¹⁰¹ PG&E’s Report, June 20, 2011 p. 6C-13 and P3-20052.

¹⁰² Response to DR 57 Q 6: Per PG&E, a copy of that list is available at <http://www.cpuc.ca.gov/NR/rdonlyres/4EF3C8C7-6895-4F3D-903B-8FC07B4B277B/0/Mar9PGETop100ErratatoCPUC.pdf>

¹⁰³ PG&E Report filed June 20, 2011, p. 6C-15.

1 pipes most likely to fail are not being identified accurately due to a lack of relevant, accurate,
2 complete and accessible data. Thus, PG&E’s current integrity management program itself
3 presents a safety risk to PG&E’s field and station employees and the public.

4 **3.4 PG&E’s Claim That Transmission Integrity Management Program**
5 **Regulations Require Special Data Is Baseless**
6

7 PG&E has been required by industry standards and by regulations to maintain records
8 about its facilities for the life of the facility.¹⁰⁴ This records retention requirement is fundamental
9 to industry because the transportation of gas is a dangerous activity. Failures in high pressure
10 pipelines, especially those containing hazardous and/or flammable materials such as natural gas,
11 can result in destruction to life and property.

12 However, as shown in the quote below, PG&E claims that TIMP imposes special data
13 management requirements well beyond the recordkeeping program PG&E already had in place.
14 When PG&E was asked why it had stated that the federal TIMP rules created new demands for
15 accessing, reviewing and integrating historical pipeline information and records in ways that its
16 existing recordkeeping systems and practices were neither designed nor intended to address,
17 PG&E responded:

18 “TIMP rules have a different focus from maintaining records to demonstrate
19 compliance, operate the system, or perform discrete engineering or maintenance
20 activities safely. TIMP rules focus on a more system-wide approach to evaluating
21 pipeline integrity. As PG&E previously explained in its June 20, 2011 response,
22 the data gathering, integration and review requirements of TIMP have presented
23 data management challenges for PG&E in particular, and the gas pipeline industry
24 as a whole.

25
26 The kinds of records that PG&E has attempted to gather, evaluate and integrate
27 include, but are not limited to: information regarding pipe characteristics such as
28 wall thickness, coating material and coating condition, pipe toughness, pipe
29 strength, and other data. . . .¹⁰⁵

30 While this may be PG&E’s position, had PG&E kept its pipeline history files up to date,
31 complete, and accurate, as required by its own internal policies in place after 1968,¹⁰⁶ PG&E
32 would have had at hand the records it needed to accomplish good integrity management, whether
33 before or after TIMP.

¹⁰⁴ See Appendix 8, Tables of Regulatory Requirements.

¹⁰⁵ Response to DR 4 Q 7-8.

¹⁰⁶ P2-400, p. 92.

1 The data requirements for TIMP are not new. Many of the data requirements of TIMP
2 are part of keeping historical records of transmission pipelines which are in original sections of
3 Part 192 from 1970 and previous California requirements in GO 112. They are the same data
4 requirements built into PG&E’s risk assessment model in 1984. Furthermore, TIMP calls for the
5 same data that any public utility seeking to “promote safety” under section 451 of the Public
6 Utilities Code would need to keep and organize for prompt and effective access. Thus, even
7 though PG&E claims TIMP has imposed substantial new challenges, it is PG&E’s inadequate
8 record maintenance that makes implementation of integrity management challenging.

9 **3.5 PG&E Changes Emphasis of Data in TIMP Model**

10 Possibly as a result of the lack of certain historical records, PG&E changed the weighting
11 of data from the original Bechtel Model (see Section 3.2 above) to the following in the current
12 TIMP model:

- 13 • Third Party: 45% (damage from hitting the pipe when digging)
- 14 • External Corrosion: 25%
- 15 • Ground Movement: 20%
- 16 • Design / Materials: 10 % (the sum of the following: pipe seam design 3, girth weld 1.5,
17 material flaws 2, pipe age, 1, MOP v. pipe strength 2, leak history 0.5, and test pressure
18 v. pipe strength 2) ¹⁰⁷

19 **4.0 MISSING AND INCOMPLETE RECORDS NEEDED FOR**
20 **INTEGRITY MANAGEMENT**

21 This section of this report identifies in more detail the missing record information that
22 PG&E would need to make its integrity management risk assessment model useful in mitigating
23 the risk of pipe failure in its transmission system.¹⁰⁸

24 As discussed above, the importance of keeping and maintaining accurate, complete, and
25 accessible records related to facility design, construction, operations and maintenance cannot be
26 overstated. Generally, good engineering practice and State and Federal regulations require
27 retaining facility-related records for the life of the facility.¹⁰⁹ Facility records are important to
28 engineers for multiple reasons, including the following:

¹⁰⁷ P2-150 and P2-157

¹⁰⁸ This section applies to all of the transmission pipelines PG&E has in service.

¹⁰⁹ P2-225(b) Records Retention, pp. 38-49.

- 1 • First, the metal in old pipe may suffer from fatigue over time and, at some point,
2 may become incapable of providing the service originally desired;
- 3 • Second, operational requirements may change over time, creating stresses the
4 facility was not originally designed to withstand;
- 5 • Third, subsequent upgrades to one part of the facility must work within the
6 design of the existing facility (or other pipeline components will require
7 upgrades); and,
- 8 • Lastly, all of these records are required to successfully manage the integrity of
9 an aging pipeline system. In all instances, the engineer must know the
10 specifications and operational history of the existing facility over its entire life,
11 in order to properly manage it and minimize the risk of failure.

12 PG&E's own 2010 guidelines for integrity management, mirroring 49 CFR 192.917(e)(3)
13 requirements, illustrate the importance of maintaining both facility and operational records:

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

- 19 (i) Operating pressure increases above the maximum operating
20 pressure experienced during the preceding five years;
- 21 (ii) MOP increases; or
- 22 (iii) The stresses leading to cyclic fatigue increase.”¹¹⁰

23 Accurate, complete, and useable pipeline records constitute a utility's best and, often, its
24 only means to understand its pipes and other components buried in the ground and out of sight,
25 and to maximize their safety.

26 Specifically, the categories in which PG&E is missing critical data from its records
27 systems are: 1) pipeline history files, 2) job files (including pipe mill reports and any QA/QC
28 testing), 3) pipeline design and pressure test records, 4) weld maps and inspection reports, 5)
29 operational history records, 6) leak records, and 7) salvaged and reused pipe records. Without
30 these records, PG&E cannot have a feasible or useful integrity management program.

31 **4.1 Pipeline History Records**

¹¹⁰ P2-158, p. 34, Section 4.3, from 49 CFR Sec 192.917 (e)(3), see RH-77.

1 PG&E has not maintained important historical records that included design, construction,
2 leak, repair and operational data, among other things. As a result, PG&E lacks critical
3 information required to make its integrity management risk assessment models useful in
4 managing risk as they are intended. In an illustration of the effect of decades of failed record
5 maintenance, PG&E's Senior Project Engineer succinctly stated the problems posed for him by
6 inadequate records. The following passage is quoted from a May 13, 2010 memo to file:

7 "In RMP-13 "Procedure For Stress Corrosion Cracking Direct
8 Assessment . . . there are certain data elements listed as required
9 for which the information is not available in the records. This
10 includes elements such as operating stress levels, hydrostatic test
11 history, pipe manufacturer, and year installed. These requirements
12 will be revised [from "required"] to the "desired" category in the
13 next procedure revision to reflect the reality of available records
14 not containing the needed information. The operating stress levels
15 are not available because of missing pipe data. With every
16 available excavation that is conducted on these or related
17 segments, we will acquire the pipe information and update our
18 records."¹¹¹ ¹¹²

19 Because PG&E is missing historical data about its pipelines, it must use erroneous and
20 incomplete (assumed and/or of unknown quality) information in its integrity management risk
21 assessment models. This lack of information has resulted in the assignment of incorrect risk
22 priorities (for replacement and assessments) to pipeline segments.

23 **4.1.1 Early Pipeline Records, Many Missing or Lacking Detail**

24 As early as 1967, PG&E claimed it had historical records. In 1967, PG&E compiled a
25 document called "Pipeline Surveillance Procedures and Records, and History File Description"
26 and submitted it to the PUC to comply with a request for copies of standard procedures, as

¹¹¹ P3-27238, Compliance Documentation, 2006 SCCDA Program, p. 22.

¹¹² P2-164 "RMP" is the designation given to a risk management procedure. This RMP-13 sets out requirements for the data required by the integrity management risk assessment model to determine risks associated with Stress Corrosion Cracking. In each such procedure there is a standard sheet that lists the various types of data they must collect. Each data element in the risk assessment model is identified as "required" (R), "desired" (D), "considered" (C), or "not required" (NR). Theoretically, the model will not run without all of the required data elements entered. The problem can be avoided where required data cannot be found by simply changing the category for that data element from R to one of the other categories. The same data element sheet is used for various purposes associated with the TIMP model to identify the types of data (elements) and to assign the appropriate R, D, C or NR codes to each element. Each sheet is unique to the part of the program (and model) it is intended to support.

1 required under Chapter V of General Order 112-B.¹¹³ This document contains the earliest PG&E
2 statement identified in this investigation of PG&E's method of keeping pipeline data. It states:

3 "Although some data, such as original and test information and special
4 surveys, are filed by main number, the majority of the data developed to
5 record replacement, reconditioning, leakage, and other operating and
6 maintenance activities are filed in numerical sequence, depending upon
7 the type record and the system used in a particular division. Reference to
8 these numbers, quite often with a brief description, is posted to the
9 pipeline plat sheets. This serves as an index to the history files and
10 presents a graphical representation of the maintenance and repair activity.
11 Some divisions also post to a full size or reduced size wall map for a better
12 overall review."¹¹⁴

13 Many of PG&E's older drawings (called Plat Sheets) are stored in the Walnut Creek
14 engineering library and are available electronically through the Engineering Library Services
15 (ELS) system. Some of the drawings that pre-date the mid-1970s contain the detailed
16 information noted in the quote above. Unfortunately, many early drawings are missing and
17 many others, including older drawings associated with projects performed in-house by PG&E
18 (instead of a contractor), lack the detail described above and supporting documentation cannot be
19 found. For instance, the Job File for the 1956 Crestmoor project that installed Line 132,
20 Segment 180, has only two drawings. The drawings contain no details about the construction of
21 the pipeline segment and there is no supporting documentation in the project file regarding the
22 pipe used, the QA/QC performed or any other test or inspection information.

23 **4.1.2 Pipeline History Files Discontinued, Now Missing**

24 By December 1969, PG&E formalized its pipeline history policy into Standard Practice
25 463.7, "Pipeline History File, Establishing and Maintaining." The purpose stated was "to
26 provide a current and uniform history record for pipelines (and mains) that have a Maximum
27 Allowable Operating Pressure (MAOP) resulting in a hoop stress equal to or greater than 20% of
28 the Specified Minimum Yield Strength (SMYS)."¹¹⁵ This Pipeline History file was to include
29 various reports relative to inspection and maintenance, as required by applicable portions of
30 PG&E's Standard Practices, including:

- 31 a. Pipeline or main number

¹¹³ P3-10005(b) p. 3 (letter) and p. 12 (report).

¹¹⁴ P3-10005(b) p. 244.

¹¹⁵ P2-400 Pipeline Survey manual, 1986, p. 90.

- 1 b. Dates of original installation and subsequent changes requiring
2 work orders
- 3 c. Design and construction data covering the original installation
4 and subsequent revisions requiring work orders or GM
5 estimates
- 6 d. MAOP of each section
- 7 e. Type of protective coating originally or subsequently installed
8 and the existing condition of the coating
- 9 f. Cathodic protection installations showing locations, ratings,
10 and installation dates.
- 11 g. Record of pipeline or main inspections
- 12 h. Record of pipeline or main leakage surveys and repairs
- 13 i. Record of location class surveys
- 14 j. Record of pipeline or main sections where hoop stress
15 corresponding to MAOP exceeds that permitted for new
16 pipelines or mains in the particular class location.
- 17 k. Initial or most recent strength test data.
- 18 l. Special studies and surveys made as a result of unusual
19 operating or maintenance conditions, such as earthquakes,
20 slides, floods, failures, leakage, internal or external corrosion
21 or substantial changes in cathodic protection requirements.
- 22 m. Annual summary of existing condition of pipelines and mains
23 based upon available records as per Exhibit A.¹¹⁶
- 24 n. Specifications for materials and equipment, installation,
25 testing, and fabrication shall be included or cross-referenced to
26 this file.¹¹⁷

27 These Standard Practice 463.7 Pipeline History Files, if implemented and maintained as
28 described above, would have provided an ongoing record of each pipeline and should have been
29 retained for the life of the facility.¹¹⁸ Accurate and complete pipeline files would have provided
30 a means to accurately prioritize pipe replacement using the risk assessment model approach.
31 This 1969 Standard Practice was included in PG&E's 1986 Pipeline Survey Manual, which also

¹¹⁶ P2-400, Pipeline Survey Manual, p. 92 refers to Exhibit A - Form 75-352. "Annual Report for Pipeline and Mains Operating at or Over 20% SMYS", See also P2-2 p. 37 (Form 75-352 is S.P. 463-7. Record retention is for Life of Facility).

¹¹⁷ P2-400 p. 91.

¹¹⁸ P2-400 p. 92, SP 463.7 Supplement, Page 2, "Records," Sec 12: "The complete and main history files shall be maintained up to date by the Division or department for the life of the operating facility."

1 included detailed instructions for creating records titled "Pipeline Survey Sheets." A PG&E
2 Vice-President directed and authorized that the records be created and maintained.¹¹⁹

3 During this investigation, when asked to produce Pipeline History Files, PG&E
4 responded, that it "believes" SP 463.7 became inoperative in the early 1990's when PG&E
5 initiated the transition to its electronic Geographic information System (GIS).¹²⁰ PG&E also
6 stated that it "no longer maintains Pipeline History Files."¹²¹ Moreover, PG&E did not produce
7 any pipeline history files in response to the data request. PG&E has not explained when or how it
8 stored or disposed of these files. However, a record produced by PG&E dated October 9, 1987,
9 shows that PG&E discontinued the policy of maintaining the pipeline files via a memo sent out
10 from the PG&E Organization Planning and Development to PG&E Department Heads. The
11 memo stated "[w]e have been asked to cancel the following Standard Practices . . . Please
12 remove and discard these SP's from your SP books."¹²² The list from the memo is shown in
13 Figure 3. The fifth item in the list, Standard Practice 463.7, discontinued a recordkeeping system
14 that had been in place for at least two decades as though it were a routine matter.

025.25-1	Air Navagation, Obstructions to
250-1	Accident Investigation-Photographs and Drawings
254-4	Damage to Customer's Electrical Equipment
441.5-4	Protection--Oper. Protective Relaying & Assoc. Auto Cntl Eq.
463-7	Pipeline History File, Establishing, and Maintaining
471.1-1	Telephone Instrument Card
522.1-2	Pipe, Bare & Coated, the Care and Handling of
550.2-4	Driver's Licenses, Medical Examinations
570-9	Use, Care, and Exchange of Padmounted Transformer Barriers
712-7	Outside Employment
726-5	Measuring in Proximity to Energized Lines or Apparatus
726-11	Accident Prevention Recognition Awards Program
726.1-1	Company Drivers' Permits
733-1	Service Emblems
750-1	Self-Contained Underwater Breathing Apparatus (SCUBA)
751.3-1	Loaning the Services of Company Employees or Company Prpty.
761.8-3	Retirement Recognition Luncheons

15

¹¹⁹ P2-400 p. 91, SP 463.7 Page 1.

¹²⁰ PG&E Response to DR7 Q9.

¹²¹ PG&E Response to DR7 Q9.

¹²² Response to DR 34 Q 1 Atch 5.

4.2 Job Files Incomplete and Disorganized

After discontinuing and apparently discarding its pipeline history files, PG&E's Job Files became PG&E's primary source of data for its integrity management risk assessment models. From at least 1929, PG&E retained engineering documents related to completed projects in Job Files. Each Job File was labeled with the Job File number assigned to the project by the accounting department.¹²⁴ According to PG&E, it keeps a master Job File, which includes a specific set of original documents.¹²⁵ The master Job File is the file of record.¹²⁶ There are also individual job files maintained by various persons working on a project. According to PG&E, documents in an individual job file generally do not become a part of the master Job File.¹²⁷

Despite being titled master Job Files, many PG&E Job Files are missing.¹²⁸ Those that do exist are frequently missing leak and pressure test results, x-ray results for field welds, field inspection logs and notes, and specific information about how the pipe itself was constructed. PG&E's files sometimes lack any clear and unambiguous record or notation regarding the source of piping – i.e. whether it was purchased new or originated from a salvaged and reconditioned pipe from another PG&E pipeline. Obviously, if the pipe had been previously used, its history and pipe characteristics would be critically important to assessing the remaining life of the pipe when it is placed back into service. This concept seems to elude PG&E since it specifically excludes previous pipe history from its risk assessment models.¹²⁹

PG&E has a history of destroying or discarding important records. Despite requirements that date back to 1912 (by California regulations) and 1970 (by Federal regulations) to retain facility related records permanently, PG&E readily admits that records may have been discarded or misplaced as early as 1980 and continuing through 1996. In Table 2A-2 of PG&E's June 20, 2011 filing, PG&E states that "Moves require recordkeeping decisions to be made, based on

¹²³ List from response to DR 34 Q 1 Attachment 5.

¹²⁴ Based on review of PG&E's Job Files that include project and accounting records.

¹²⁵ Response to DR 51 Q 4

¹²⁶ Response to DR 17 Q 5.

¹²⁷ Response to DR 17 Q 5.

¹²⁸ See Testimony of Paul Duller, Records Expert for CPSD in this proceeding.

¹²⁹ P2-158.

1 current operational needs, engineering judgment and recordkeeping requirements, [1980-1996]”
2 and “some pipeline records were misplaced or discarded around this time frame [1995-1996].”
3 When questioned about the missing records, PG&E explained:

4 “Based on available information, we have concluded that some
5 records went missing or were destroyed during this time frame.
6 However, we have been unable to conclusively determine which
7 records are missing or the time period in which they were lost.
8 Moreover, it is also possible that during these (sic) time frame or
9 other time frames, additional records, including so called “life of
10 the pipeline” records may have been misplaced or discarded.”¹³⁰
11

12 Missing Job Files, which are the primary source of information about the construction of
13 PG&E’s pipelines, means missing data that is required for a successful risk assessment of its
14 pipelines.

15 **4.3 Many Design and Pressure Test Records Missing**

16 PG&E is missing many pipeline design & pressure records, which are vital to the
17 successful implementation of the company’s integrity management risk assessment model.
18 Despite specific PG&E policies which include instructions to retain traceable and verifiable
19 design and test records, PG&E has failed to do so. PG&E states “Some records to validate the
20 Maximum Allowable Operating Pressure (MAOP) are still under investigation and may be
21 missing.”¹³¹

22 PG&E formally incorporated design and test requirements for piping systems into its
23 Standard Practices at least as early as 1965.¹³² Before then, PG&E followed ASME and API
24 guidelines.¹³³ According to PG&E, the purpose of its 1965 Standard Practice 1604, “Design and
25 Test Requirements for Gas Pipe Systems,” was to establish a uniform company policy for
26 designing and testing gas piping systems that would conform to the requirements of G.O 112A.
27 Standard Practice 1604, section 30 states “[t]he copy of the Strength Test Pressure Report filed
28 with the completed foreman’s copy of the estimate shall be retained for the life of the facility.”¹³⁴

¹³⁰ PG&E response to DR 4 Q5-6, PG&E repeats this response for several time frames in Table 2A-2 of its June 20, 2011 filing.

¹³¹ Response to DR 4 Q 5-6.

¹³² Response to DR 18 Q 8 Attachment 1.

¹³³ Response to DR 1 Q 17.

¹³⁴ Response to DR 18 Q 8 Attachment 1.

1 Standard Practice 1604 was updated in 1970 and renamed A-34, Drawing Number
2 087712.¹³⁵ The 1983 A-34 policy cites 49 CFR 192.101 and 192.501, in addition to CPUC GO
3 112. Section 25 of Standard Practice A-34 requires that “a chart record shall be made of the
4 pressure test for all lines or systems being uprated and for new or reinstated facilities to operate
5 at or over 30% Specified Minimum Yield Strength (SMYS),” then specifies the information,
6 including the pipe design specifications, to be recorded on the back of the chart. Standard
7 Practice 1604, section 25.1 of Standard Practice A-34 states that “The original of the test chart is
8 to be attached to the original of the Test Report Form 62-4921. A copy of the test chart is to be
9 attached to each copy of the test report. This record is to be retained for the life of the
10 facility.”¹³⁶ PG&E’s latest Standard Practice A-34 policy is dated 2003 and still includes a
11 record retention clause with wording similar to that of the 1983 version requiring the record to be
12 retained for the life of the facility.¹³⁷ Unfortunately, many of these records were not retained – a
13 loss of information critical to the accuracy of an integrity management risk assessment model
14 and vital to the safe operation of PG&E’s pipelines.

15 **4.4. Weld Maps and Inspection Records Mostly Missing or Incomplete**

16 In October 1963, PG&E developed a Standard Practice to “establish a minimum weld
17 check by radiographic or visual examination procedures on all gas piping systems, in accordance
18 with General Order 112”.¹³⁸ In this same Standard Practice, PG&E’s records retention policy
19 calls for retaining weld inspection reports for the life of the facility.¹³⁹ However, in practice,
20 PG&E does not retain x-ray films beyond about 5 years.¹⁴⁰ And, despite PG&E’s policies to
21 create and manage weld records, few weld records can be found in PG&E Job Files. The weld
22 records that are found are generally copies of weld inspection logs that were prepared for an
23 inspection but were never completed with the inspection results.¹⁴¹

¹³⁵ PG&E’s practice until just recently was to formalize some of its attachments to standard practice documents as “drawings” using the same title blocks, signature block, dating and version numbering as used on facility drawings. Thus, sometimes these records are referred to by drawing numbers instead of attachments to a Standard Practice.

¹³⁶ Response to DR 18 Q8 Attachment 6 (1983), also P2-939 (1986).

¹³⁷ Response to DR 18 Q 8 Attachment 14 (2003).

¹³⁸ P2-1286, SP 1605.

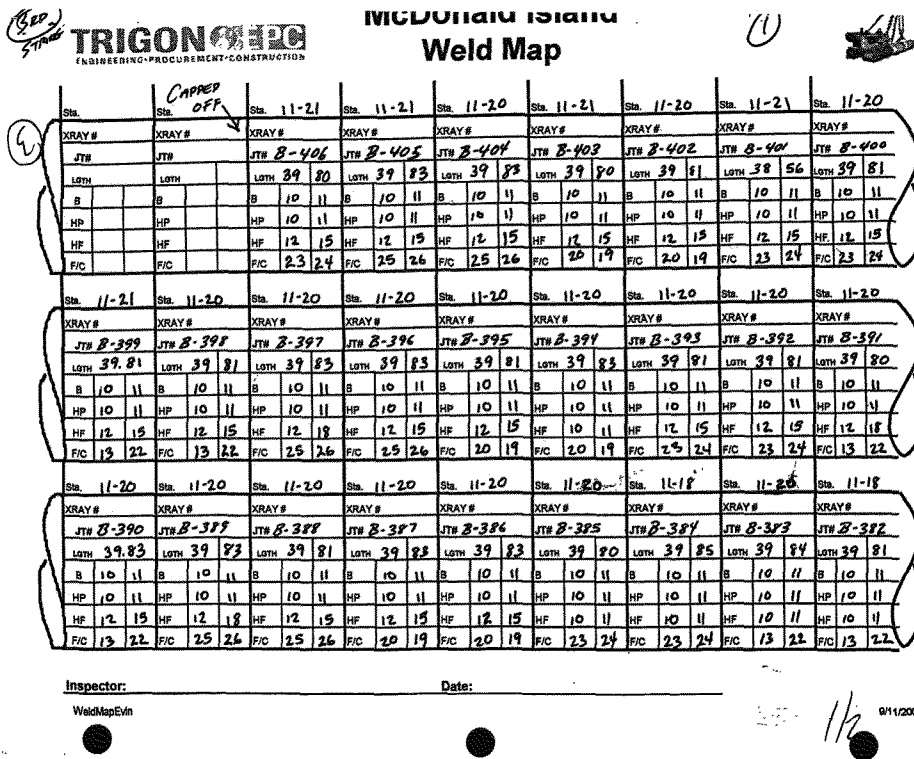
¹³⁹ P2-1286, SP 1605.

¹⁴⁰ Based on discussion with PG&E in Rocklin Office when viewing X-Ray films stored at that location.

¹⁴¹ From review of ECTS records.

1 Weld maps and inspection records for PG&E's transmission pipelines, which would normally be
 2 a source of key pipeline data for the integrity management risk assessment model, are mostly
 3 missing.¹⁴²

4 The maps generated during a construction project that show the location and orientation
 5 of welds on a pipeline are called Mainline and Tie-in Weld Maps.¹⁴³ A thorough review of many
 6 job files in PG&E's new Enterprise Compliance Tracking System database revealed very few
 7 such weld maps, even though they should have been retained in the master Job File according to
 8 PG&E's policies.¹⁴⁴ These missing weld maps would provide invaluable information to PG&E in
 9 its current efforts to locate and evaluate welds.



10
 11

Figure 4¹⁴⁵

¹⁴² Response to DR 14 Q1.

¹⁴³ Response to DR 14 Q1 Attachment 1 & 3.

¹⁴⁴ Response to DR 15 Q 6 – ASME/ASA B31.1.8 and API 1104.

¹⁴⁵ Response to DR 14 Q 1 Attachment 2.

1 In addition to weld maps, inspection reports are an important source of information about
2 the quality of welds. However, PG&E has not retained very many weld inspection reports.
3 Records of weld inspections might be found in the construction engineer's field notes taken
4 daily by the engineer overseeing a project in the field. PG&E's policies do not require the
5 inclusion of field notes in the master Job File. In fact, it seems they are not necessarily included
6 in the personal job files either, but may be kept in various types of notebooks or log books at the
7 preference of each engineer. Some Job Files in the Enterprise Compliance Tracking System
8 database include field notes, but most do not. When asked to produce field notes, PG&E
9 responded that it could not locate field notes for a specific list of pipelines.¹⁴⁶ PG&E states that
10 "[i]nformation contained in the documents provided by field engineers is typically transferred to
11 appropriate forms and records used by PG&E to document its facilities. PG&E does not (and
12 has not to the best of its knowledge) maintain a formal recordkeeping practice relating to field
13 engineer notes."¹⁴⁷

14 The importance of weld inspection records is illustrated by reviewing the weld inspection
15 report found for the 1948 installation of Line 132 from Crystal Springs to the Martin Station (Job
16 File Number 98015). This report shows a number of longitudinal and circumferential welds that
17 were cracked or that contained anomalies or inclusions. Some of the welds were repaired. Other
18 circumferential and longitudinal welds, characterized as sloppy, containing gas pockets, and
19 inclusions, were checked off as accepted, allowing the pipe with defective welds to remain
20 installed in the transmission system.¹⁴⁸ Only 10 % of the welds in the line were x-rayed, so there
21 is no way to determine how many additional welds in the pipe that was installed in that project
22 were also bad. Sections of that pipeline were subsequently replaced when the line was relocated
23 to make way for various development projects during the period 1950-1985.¹⁴⁹ In most
24 instances, the pipe that was replaced was salvaged.¹⁵⁰ Any of the pipe that was salvaged may
25 have included some bad welds. PG&E reused the salvaged pipe on other projects but did not

¹⁴⁶ Response to DR 17 Q 1 and Response to DR 17 Q 1 Attachment 1.

¹⁴⁷ Response to DR 17 Q 1.

¹⁴⁸ PG&E ECTS documents MAOP05400964, MAOP05400966, MAOP05400967, MAOP05400970,
MAOP05400971, MAOP05400980, MAOP05400987 and Response to CPSD 194 Q 11 Attach. 1.

¹⁴⁹ Response to DR 7 Q 12.

¹⁵⁰ Based on the author's review of thousands of historical documents in PG&E's ECTS database.

1 keep track of where the pipe was reused in the system.¹⁵¹ Apparently, the weld records did not
2 accompany the salvaged pipe. PG&E has never had a formal policy or practice of inspecting the
3 welds in salvaged pipe before it is reused.¹⁵²

4 There is very little weld data in the current integrity management risk assessment model
5 for most pipeline segments because PG&E did not keep the records and any records that may
6 exist cannot be found.¹⁵³ As mentioned in Section 3.0 of this report, there are several data fields
7 for weld data built into the integrity management risk assessment model. Unfortunately, due to
8 the lack of data, there are no entries for weld data for many pipeline segments.¹⁵⁴

9 **4.5 Many Operating Pressure Records Missing, Incomplete or Inaccessible**

10 The operating pressure history over the life of the pipe is a critical record for any piping,
11 including natural gas pipelines. This record should keep track of normal operating cycles
12 showing high and low pressures as evidence of the pressures to which the piping is subjected
13 under normal operating conditions. The highest pressure and durations at that pressure over
14 specified periods (for instance, daily, weekly, or monthly) should always be recorded because
15 they will be used by engineers to analyze such things as the condition of the pipe and welds
16 (especially those known to have a manufacturing threat such as Electric Resistance Welded
17 Pipe),¹⁵⁵ any risk associated with continued operation at routine pressures, the possibility of
18 uprating to a higher MAOP, the risk of failure, or the expected life of the pipe. In assessing
19 corrosion risk relative to the expected life of the pipe (a pipe wall made thin by corrosion could
20 leak under normal operating pressure), PG&E recognizes the importance of pipeline operating
21 pressures in its Risk Management Procedure, noting that the pipeline operating pressures are
22 “required” for risk assessment and stating that significant changes in pressure may trigger new

¹⁵¹ See Section 4.7 of this report for more discussion about salvaged and reused pipe.

¹⁵² Response to DR 3 Q 10, but see 1988 Memo Response to DR 10 Q 5 Attachment 6.

¹⁵³ For example, in response to DR15 Q6 PG&E admits that with respect to the 1956 installation of Segment 180, it has not located pressure test or x-ray documentation, standard tests to prove the integrity of welds when they are completed on an installation project.

¹⁵⁴ An additional source of weld quality data is technical reports resulting from metallurgical analysis of pipe welds that are either suspect or that failed. PG&E performs these analyses at its San Ramon ATS facility and also contracts out to various labs. The records experts for this OII, Paul Duller and Alison North estimate that approximately 17 % (13,228) of the analytical investigation reports are missing.

¹⁵⁵ P3-27410, p. 2, Define manufacturing threat.

1 DG-ICDA regions.¹⁵⁶ The same pressure history recordkeeping is crucial to other considerations
2 (e.g. weld integrity) of integrity management as well.

3 PG&E keeps some pressure excursion information in abnormal incident reports, but these
4 reports appear to stand alone, and are not integrated into any particular historical record of
5 operating pressures.¹⁵⁷ Pressure history recorded in SCADA began in 1986, but records are
6 probably only readily accessible back to 2003, when the SCADA system was upgraded to the
7 current program.¹⁵⁸ Generally, PG&E has no “life of the plant” record of operating pressures for
8 the life of its pipelines. Moreover, PG&E acknowledged that it recently lost pressure records for
9 all of 1999 for all pipelines in its system.

10 “In 2004, Gas Operations migrated the data base used to capture
11 SCADA pressure records from an (sic) the existing server to a
12 more powerful server (the Ascon server). The process of
13 migrating the records to the Ascon server required using back-up
14 tapes of SCADA records from prior years, as the existing server
15 did not contain a historian function that permitted storage of and
16 access to pressure records from prior years. During that migration
17 process, the Gas Control ISTS team building the new database
18 discovered that the back-up tape for 1999 did not contain the 1999
19 pressure records data. The team did not know the circumstances
20 accounting for why the 1999 back-up tape did not contain the data.
21 They tested the tape to see whether the data was on the tape in a
22 corrupted form that perhaps could be recovered, but the tape did
23 not contain the data. As a result, the new database does not have
24 historic pressure records from 1999 for any PG&E pipelines.”¹⁵⁹

25 Because of this loss of one year of pressure records, PG&E simply cannot give an
26 accurate accounting of pressure excursions above MAOP for any pipeline in its system, which
27 means the company cannot accurately assess the condition of any of its pipelines.

28 PG&E does not have the historical operating pressure records needed for its integrity
29 management risk assessment models. Because these pressure records are required elements for
30 the integrity management risk assessment models, PG&E must enter a number into the model for
31 each pipeline segment, whether or not there is a factual basis for the pressure selected.

¹⁵⁶ P2-390, p. 26, DG-IGDA is Internal Corrosion Direct Assessment for a Dry Gas pipeline.

¹⁵⁷ Response to DR 7 Q 1, Abnormal Incident Reports

¹⁵⁸ Response to DR 4 Q 9.

¹⁵⁹ Response to DR 15 Q 10.

1 Obviously, entering an incorrect pressure will contribute to an inaccurate risk ranking of pipeline
2 segments by the model.

3 **4.6 Leak Records Incomplete, Disorganized and Inaccessible**

4 PG&E has failed to maintain leak records in a manner that makes the information readily
5 accessible and states that it cannot retrieve leak data prior to 1970. Yet, PG&E also says 20
6 percent of its lines were installed prior to 1970.¹⁶⁰ Information about past leaks in existing
7 pipelines is a category of data fundamental to predicting likely leaks in those pipelines in the
8 future. The probability model needs “cause of leak” data to complete the risk calculations in the
9 model.¹⁶¹ For pipelines that have not had a post construction pressure test, it is essential that the
10 number and type of leaks on that pipeline and similar pipelines are known. If such data is not
11 available or is suspect, then the stability of the pipeline with regard to materials and construction
12 threats cannot be determined since leak data is critical to determining stability.

13
14 A review of PG&E’s various forms (all referred to as “A-Forms”) used to collect leak
15 information reveals inconsistent reporting, incomplete reports and poor follow up. “For instance,
16 in 2006, integrity management staff documented 13 leaks in line 132 between 1964 and 1988
17 based on A-forms. Of the 13 leaks identified, PG&E could determine the cause of only 1 leak
18 because no cause was documented on the A-forms for the other 12 leaks”.¹⁶³ Without a
19 documented cause, it would be impossible to assign the leaks to the model in the appropriate data
20 fields for calculation of likelihood of failure due to corrosion, third party, ground movement,
21 weld quality, etc. Over the years, the data has been stored in binders at local offices, in
22 engineering offices, and in various databases. Once the data was uploaded to databases, PG&E
23 found that it was unable to include the historical data from one database to the next and thus
24 ended up with at least three different databases containing different sets of leak data, in addition
25 to paper records. As a result of this disorganization of basic leak records, PG&E has been unable

Deleted: The risks of allowing leaks to go unattended include exposing people to harmful gas, the potential for explosions where gas accumulates in closed areas, and total pipe failures resulting in catastrophic damage like the San Bruno pipe failure in September 2010. Every company that transports natural gas through pipelines must have an active leak detection program to protect the public. PG&E has had a leak detection program since at least 1958.¹⁶² Unfortunately, even though it had a leak detection program in place, it failed to document and save the data in a way that made the data retrievable.

Deleted: For instance, in 2006, integrity management staff documented 728 leaks in Line 132 between 1964 and 1988 based on A-Forms. Of the 728 leaks identified, PG&E could determine the cause of only 2 leaks because no cause was documented on the A-forms for the other 726 leaks.

¹⁶⁰ Response to DR 42 Q 7 ((1076 miles*100)/5324 miles = 20%).

¹⁶¹ 1984 Bechtel Report. The Bechtel models and reports are discussed in Section 3.0.

¹⁶³ P3-24119 p. 9.

1 to respond to requests in this investigation to produce lists, counts, and characteristics of past
2 leaks on particular pipelines.¹⁶⁴

3 Although they are the primary record regarding leaks, PG&E's A-Form reports are
4 poorly managed, inconsistent, and incomplete. Leaks reported from leak surveys, employees,
5 and third parties are reported on A-Forms. The leaks are graded from 1 to 4, with grade 1 being
6 the most critical, requiring immediate attention. Grade 3 and 4 leaks can remain in the system,
7 unattended for months, even years. These leaks are monitored for a change in grade. In the
8 records, it appears some of these leaks "disappear" after subsequent surface testing reveals no
9 reading on a test instrument.¹⁶⁵ As of November 10, 2011, PG&E reported for its transmission
10 lines no active Grade 1 leaks, 16 active Grade 2 leaks, 145 active Grade 3 leaks and 609 Grade 4
11 leaks.¹⁶⁶ The records for these leaks are kept in the integrated gas information system database
12 which is the current database that contains A-Form information.¹⁶⁷ The A-Forms are filed in
13 notebooks in the division offices.

14 A review of A-Forms that PG&E collected from the regional offices and from various
15 other records files and produced in this proceeding reveals that the A-Forms program has been
16 poorly managed. These forms have changed over time so that the historical record is
17 inconsistent. Plus, the A-Form is designed for multiple purposes and uses. For instance, the
18 person who initially reports the leak may fill out one part of the form. A person who goes out
19 and rechecks the leak must find the original form and fill out the next part of the same form. A
20 person who digs up the leak and repairs it will fill out yet another part of the form. PG&E
21 explains as follows:

22 "PG&E's Leak Repair, Inspection, and Gas Quarterly Incident
23 Report (also referred as an "A-Form") typically constitutes
24 PG&E's field report of observed conditions relevant to gas
25 transmission leaks, including leaks on welds. This document is
26 filled out by field personnel responsible for leak detection,
27 inspection, and repair. Over time, the form has evolved to call for
28 field employees to gather a substantial amount of data including
29 pipe specifications, soil type, cathodic protection, and external pipe

¹⁶⁴ Response to DR 40 Q 3.

¹⁶⁵ Example A-Forms are provided as Appendix 5 to this report.

¹⁶⁶ Response to DR 23 Q 16.

¹⁶⁷ PG&E states that leaks from the IGIS database are mapped to pipelines in the GIS mapping system, but admits that the mapped location of each leak is not accurate.

1 condition. The form also calls for determination of leak source and
2 leak cause. PG&E produced the earliest-located revision of this
3 document (dating back to 1979) in the June 20, 2011 OII response
4 as attachment P2-1152. Physical copies of A-Forms are
5 maintained locally in the gas division and district offices
6 responsible for the gas facility that led to creation of the A-Form,
7 as well as in gas transmission and distribution mapping offices. A-
8 Forms are organized in varying fashion across offices. Some local
9 offices organize A-Forms by date. Others organize A-Forms by
10 geographic location (wall map and plat). In some instances, such
11 as where an A-Form is associated with a construction project, the
12 A-Form may be in a job file. Since approximately 1970, electronic
13 records of A-Forms have been created and stored in PG&E's
14 electronic leak databases. PG&E's policy is to maintain hard copy
15 A-Forms for the life of the facility."¹⁶⁸

16 The risks of allowing leaks to go unattended include exposing people to harmful gas, the
17 potential for explosions where gas accumulates in closed areas, and total pipe failures resulting
18 in catastrophic damage like the San Bruno pipe failure in September 2010. Every company that
19 transports natural gas through pipelines must have an active leak detection program to protect the
20 public. PG&E has had a leak detection program since at least 1958.¹⁶⁹ Unfortunately, even
21 though it had a leak detection program in place, it failed to document and save the data in a way
22 that made the data retrievable.

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23 The A-Form is one of PG&E's oldest record systems. However, A-Forms are frequently
24 only partially completed, even within the portion to be filled out by any one individual.¹⁷⁰
25 Further, leaks are rarely graded on the A-Form, which begs the question of how a grade is
26 ultimately assigned, and who makes that decision when the leak information is entered into a
27 database. For these reasons, A-Forms are an incomplete record of leaks and the ones that do
28 exist are difficult to use as a resource of leak data for the integrity management program.

29 PG&E says that it maintains leak records for the life of the facility, plus 6 years (later
30 revised to Life of Facility in records retention plans).¹⁷¹ But, when asked if it could simply count
31 the total number of leaks that it has had on each transmission line since installation, PG&E
32 responded that it could not, stating:

¹⁶⁸ Response to DR 4 Q 12.

¹⁶⁹ P2-1149, Standard Procedure 460.21-4, 1966 – indicates it replaced a 1958 version.

¹⁷⁰ See Appendix 5 to this report.

¹⁷¹ P2-2, 2010.

1 “No. PG&E believes that taken together its leak records and
2 databases contain information about substantially all leaks on the
3 gas transmission system. However, the records are not fully
4 integrated, making it difficult to count the total number of leaks
5 across the entire transmission system.”¹⁷²

6 In light of the earlier discussion citing Bechtel’s conclusion that leak information is one
7 of the most important sources of information for integrity management, the inability to find leak
8 records for each transmission line raises serious safety concerns. The history of leaks caused by
9 corrosion is also an important component of PG&E’s integrity management program, yet PG&E
10 effectively has no means to track the history of corrosion in any particular pipeline segment or to
11 accurately and meaningfully incorporate that history into integrity management. Since leak data
12 is another essential element of the integrity management risk assessment model, the lack of this
13 data renders the model useless in accurately calculating likelihood of failure for any specific
14 pipeline segment.

15 **4.7 No Tracking System for Salvaged and Reused Pipe**

16 Over the years, PG&E moved pipe (often in service for many years) from one location to
17 another within its system but did not keep track of where the pipe was reinstalled in the
18 transmission system, making it now impossible to accurately determine the age of pipe in any
19 segment.

20 In 1957, PG&E commented on the Commission’s proposed General Order:

21 “These paragraphs stipulate that no used pipe or pipe of unknown
22 specification should be used at pressures exceeding 300 psig. The
23 American Standard Code details complete and adequate procedures to be
24 followed to qualify such materials for use and to insure that safe
25 installations result. It has been Company experience that pipe salvaged
26 from gas lines in service for many years under severe conditions is in
27 general good pipe. With proper inspection, repair and test, re-use of this
28 material should be permitted. The staff’s draft does not consider the effect
29 of the actual working stress in connection with re-used pipe. The 300 psig
30 pressure limit is arbitrary in that it fails to take into consideration the
31 thickness of such pipe. For example, salvaged 16" x 1/2" wall thickness
32 pipe could not be used for a 300 psig operating pressure even though the
33 steel stress would be only 4800 psig. On the other hand, 16" x 1/4"
34 salvaged pipe could be used for a 299 psig pressure although the steel
35 stress would be 9568 psig.”¹⁷³

¹⁷² Response to DR 40 Q2.

¹⁷³ Response to DR_033-Q10, Atach 2, p. 3.

1
2 According to this comment PG&E believed that it was acceptable to re-use pipe, but also
3 stated that proper inspection, repair and testing was required prior to re-use. However, PG&E
4 never implemented such a program.¹⁷⁴

5 In the process of reviewing PG&E records it has become apparent that PG&E has
6 salvaged and reused transmission pipe now operating in its system that may not be satisfactory
7 for continued service. This conclusion is based on weld radiography reports that show
8 acceptance of marginal and bad welds on pipe that was subsequently salvaged and sent to the
9 company storage yard for reuse elsewhere in the system. PG&E has a practice of salvaging pipe
10 when it is removed from the ground, for instance when a highway or development project
11 requires the relocation of a gas transmission line.¹⁷⁵ This practice has apparently always existed
12 within PG&E, although, PG&E currently requires pipeline materials to satisfy specifications and
13 standards set forth in its own Standards A-16 and A-34, and currently has a policy that prohibits
14 the installation of reconditioned or used transmission pipeline fittings, such as elbow, tees,
15 reducers and caps.¹⁷⁶ Reusing pipe is an acceptable practice as long as the salvaged pipe is
16 inspected and tested as necessary to confirm the integrity of the pipe for reuse within the design
17 requirements for the new installation.¹⁷⁷ However, even if it is inspected, it would always be
18 prudent to keep track of where the older pipe is within the system in case an issue arises later
19 related to the earlier fabrication of the pipe or prior abnormal operating events involving the
20 pipe.

21 PG&E states that it never has had policies to track salvaged, reused and/or reconditioned
22 pipe within its system.¹⁷⁸ Yet, it appears that PG&E's early accounting and engineering

¹⁷⁴ Response to DR 16, Q1; Response to DR 10 Q 5 and DR 10 Q 2.

¹⁷⁵ As evidenced on numerous project face sheets, accounting documents that record authorization and completion of projects. The forms used include a section for recording the amount of pipe salvaged so that the value of the salvaged pipe can be credited to the appropriate account. Example Face Sheet showing salvage – See Appendix 7 to this report.

¹⁷⁶ Response to DR 10 Q5 and DR 10 Q5, Attachment 3.

¹⁷⁷ For instance, PG&E had a special inspection process for A.O. Smith pipe that was initially installed in the 1920s-30s as "PG&E Spec Pipe", then later salvaged and reused in the 1950's – 60's. Response to DR 10 Q 5 Attachment 06.

¹⁷⁸ Response to DR 16, Q1; Response to DR 10 Q 5 and DR 10 Q 2. Note: In response to DR 10 Q 2, PG&E states that salvaged is synonymous with reconditioned (as opposed to "salvaged" meaning scrapped or junked).

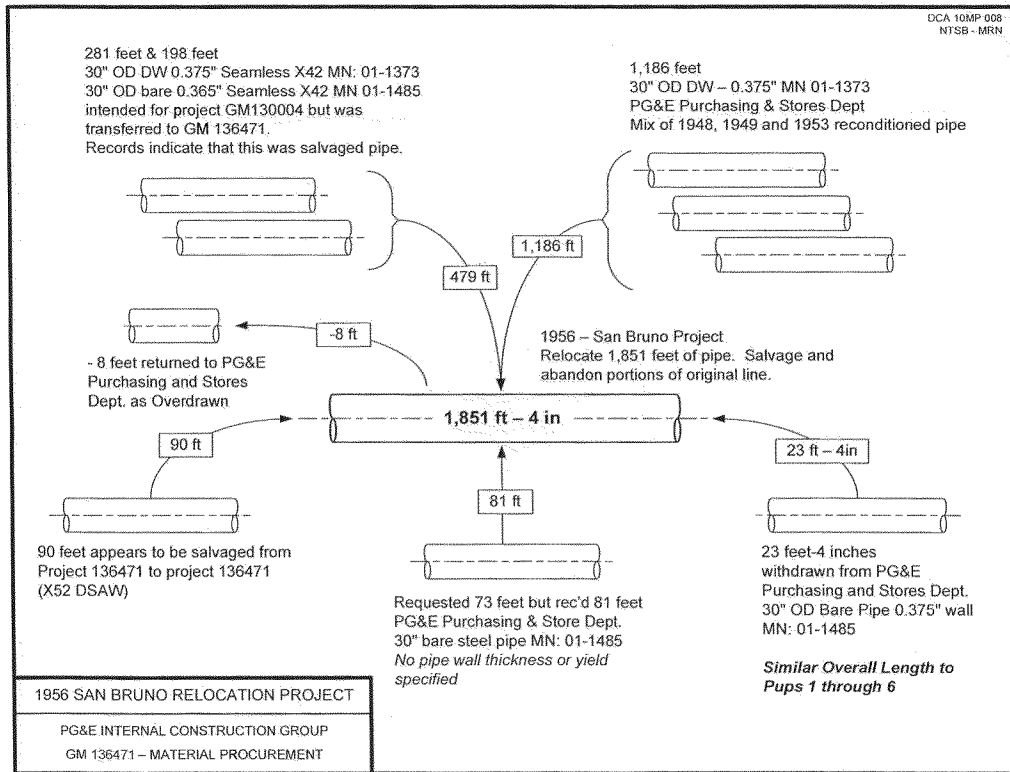
1 documents did keep track of salvaged and reused pipe.¹⁷⁹ For instance, there are some
2 construction drawings that include notes about pipe having been salvaged and abandoned, and
3 about small pieces of pipe having been welded together at Milpitas Storage Area before being
4 delivered to a construction site.¹⁸⁰ A review of records in Job files reveals various types of
5 accounting documents and notes on project documents and construction drawings that show the
6 salvaging, reconditioning and abandoning of pipe. Some historical details in Job Files suggest
7 that PG&E once had this tracking capability because there are notes on project face sheets stating
8 that pipe is to be salvaged or abandoned and also stating the original installation project and date
9 of the pipe.¹⁸¹ At some time in the past, PG&E apparently lost track of these records. In fact,
10 after months of its own research, PG&E pieced together the potential sources of pipe that went
11 into the 1956 construction of Line 132, Segment 180 that failed in San Bruno. These records
12 reveal that most of the pipe was salvaged and reconditioned from other pipelines in the PG&E
13 system, but they do not identify the previous locations of the pipe, or its age.¹⁸² (Figure 5)

¹⁷⁹ Based on review of thousands of records in the ECTS database.

¹⁸⁰ Response to DR 24 Q 1 & Q 2, Response to DR 7 Q 12 Attachment 4.

¹⁸¹ See example at Appendix 6 to this report.

¹⁸² Figure 5 - From Response to NTSB Exhibit 2-DV. File #460235.



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Figure 5¹⁸³

In 1979, in what appears to be an intentional effort to eliminate records that show the use of salvaged pipe, PG&E’s drafting instructions in Mapping Standards 410.21-1, section II.3, states “salvaged and abandoned mains – to be removed from plat sheets.” The instructions offered no additional explanation as to why the information should be removed.¹⁸⁴ Generally, based on reviewing thousands of documents in the Enterprise Compliance Tracking System (ECTS) database, it appears that sometime in the 1980’s PG&E lost the ability to track salvaged pipe.

It seems likely that if PG&E had maintained its accounting records for capital investments over the life of the facilities as it should have, in accordance with regulations and

¹⁸³ NTSB_460235, NTSB Docket No. SA-534, Exhibit No. 2-DV. Note: This figure shows that 281’ and 198’ of seamless pipe was used, making this document one more PG&E record that is inaccurate since 30” seamless pipe was never manufactured.

¹⁸⁴ P2-323, p. 16

1 general accounting principles, it now would have a detailed record that could be used to track
2 salvaged pipe to reconditioning and reinstallation in another project.¹⁸⁵

3 During this proceeding, CPSD disclosed records discovered in the ECTS database
4 showing that PG&E salvaged and reused pipe from Line 132 that had been documented during
5 original construction in 1948 as having bad welds.¹⁸⁶ It is impossible to determine where this
6 salvaged pipe ended up in the system. After the disclosure, PG&E attempted to track these pieces
7 of salvaged pipe but was largely unsuccessful. In its response dated November 15, 2011, PG&E
8 repeatedly stated “[a]s part of PG&E’s MAOP validation project, reconditioned pipe currently
9 installed in the gas transmission system is being catalogued and tracked.”¹⁸⁷ In fact, a column
10 for reconditioned/salvaged pipe was added to PG&E’s pipeline features list (PFL) spreadsheet on
11 September 1, 2011.¹⁸⁸ By that time, over 2.2 million Job File documents had already been
12 scanned into the ECTS database, viewed and catalogued.¹⁸⁹ Most of the records identified
13 during this investigation by CPSD were found during random checks of pages of Job Files listed
14 in PG&E’s ECTS “non-Pipeline Features List” category. To find and add all of the relevant
15 pages to the Pipeline Features List, someone would have to find the documents in ECTS and
16 catalog them – not an easy task when there are millions of pages that were scanned in as
17 unsearchable images. To find the salvaged pipe in PG&E’s system, each page of ECTS must be
18 individually opened and viewed.

19 PG&E’s new program of implementing a tracking system to identify and track
20 reconditioned and salvaged pipe is an effort to address the deficit in its previous recordkeeping
21 programs. Unfortunately, the great amount of time it will take to identify and account for used
22 pipe in the system could be punctuated by additional pipe failures. And, even if the pipe is
23 located, PG&E still must figure out when it was originally purchased, what its design
24 characteristics are, and the service conditions it was exposed to over time. Because PG&E has
25 moved pipe from one location to another within its system without keeping track of where the

¹⁸⁵ Response to DR 33 Q 1, Attachment 1 1938 Records Retention Schedule.

¹⁸⁶ Project Number GM 98015.

¹⁸⁷ PG&E’s Updated Supplemental Response to LD’s “Notice and Disclosure of Safety Evidence and Companion Motion for Public Release of Evidence”, I.11-02-016, filed Nov 15, 1011.

¹⁸⁸ Response to DR 16 Q 5.

¹⁸⁹ Response to DR 39 Q1.

1 pipe went, it is now difficult to state in the integrity management risk assessment model the age
2 of pipe in any pipeline segment.

3 Finally, the loss of records about the location of salvaged pipe means PG&E cannot
4 determine that pipe specifications data entered into its integrity management risk assessment
5 model is accurate for every pipe segment. This uncertainty creates an ongoing safety risk
6 associated with using the integrity management risk assessment model to prioritize pipe projects
7 based on likelihood of failure or highest risk.

8 **5.0 BAD DATA IN THE GEOGRAPHIC INFORMATION SYSTEM**

9 PG&E's Geographic Information System (GIS) replaced most of PG&E's paper records
10 for documenting facility data, but the database was populated with faulty data, including
11 assumed and missing elements from earlier databases making it an unreliable source of data for
12 the integrity management risk assessment models.¹⁹⁰ In spite of the GIS's critical importance to
13 engineering and operations, that database cannot be more reliable than the records used to
14 populate it. In addition, its usefulness is limited because the system is populated with many
15 blank and assumed entries.

16 When asked to state the number of miles of pipeline in PG&E's transmission system that
17 have one or more assumed or unknown values in the GIS and the pipeline survey sheets, PG&E
18 answered "approximately 5,324 miles," which is the total number of miles in service in PG&E's
19 transmission pipeline system.¹⁹¹ Indeed, PG&E produced a list showing the assumed and blank
20 values in the GIS system for every segment of each pipeline.¹⁹² Thus, important data for
21 pipelines throughout PG&E's system is either assumed or unknown.

22 When PG&E was asked about its Quality Assurance/Quality Control (QA/QC) program
23 related to the transition of data from hard copy records to the electronic GIS, it stated: :

24 "PG&E has been unable to locate or identify any documentation or
25 formal procedures relating to quality control and/or quality
26 assurance of the data transfer from hardcopies to pipeline survey

¹⁹⁰ GSAVE, PG&E's first gas transmission GIS program, was deployed in May 1998. GSAVE was a customized program composed of scripts and tools built using ESRI's ArcInfo 7.x and ArcView 3.x software base. GSAVE was operational until November 2003. GasMap 1.0 and GasView 1.0 replaced GSAVE in November 2003. GasMap and GasView were also custom GIS applications developed by PG&E using ESRI ArcGIS 8.x software. GasMap and GasView migrated to ArcGIS version 9.x in 2005. PG&E deployed GasMap 2.0 in July 2011. GasMap2.0 is based on ArcGIS 9.3.1.

¹⁹¹ Response to DR 27 Q 12 & 13.

¹⁹² Response to DR 27 Q 12 Attachment 1 & 2.

1 sheets, and from pipeline survey sheets to GIS. Given the passage
2 of time, it is difficult for PG&E to identify what QC/QA processes
3 may have existed.”¹⁹³

4 Errors in records have been carried forward from one system to the next without checks
5 for accuracy or, in some cases even reasonableness. As stated above, PG&E has no record of a
6 QA/QC program for the transfer of data into the GIS.¹⁹⁴

7 **6.0 RECORDS LOST IN PG&E’S ENTERPRISE COMPLIANCE**
8 **TRACKING SYSTEM DATABASE**

9 PG&E is now in the process of consolidating all of its Job Files into the Enterprise
10 Compliance Tracking System. In ECTS, the master Job File has been combined with individual
11 Job Files under the same job number. While the master Job File documents are identified in the
12 database as coming from the Walnut Creek engineering library, the total number of documents in
13 any one Job File is now so huge that it is difficult to review the records and locate critical
14 documents. In addition, there is an excessive amount of duplication in the ECTS database,
15 making it cumbersome to use.¹⁹⁵

16 Since each page is scanned as a separate image document, PG&E cannot search these
17 pages to find anything, including field notes. It would take hundreds of hours to open each page
18 and look at it. So, for now, PG&E’s Job File records are essentially lost in its own ECTS
19 database.

20 **7.0 CONCLUSION**

¹⁹³ Response to CPSD DR 215 Q6.

¹⁹⁴ For example, there is an error in GIS that comes directly from a pipeline survey sheet. QA/QC weakness appears in the GIS rendition of the pipeline survey sheet for L-132, dated 9/11/2011. In this record, PG&E shows that Segment 180 was pressure tested with gas in 1961, but admits it has not identified any records related to the 1961 gas test. However, there are no records of such a test in the Job File. PG&E responded to a request for test records that “with respect to the 1956 installation of Segment 180, PG&E has not located pressure test or x-ray documentation.” PG&E believes this gas test information came from a 1968 report filed with the PUC that indicates a gas test occurred in 1961. However, careful inspection of that record finds that in 1968 PG&E reported that the piece of L-132 between MPs 39.04 and 39.37, which represent the current location of Segment 180, was installed in 1948. Thus, by 1968 PG&E had apparently already misplaced its records that showed the 1956 project relocation of Segment 180.

Response to DR 7 Q 12 Attachment 83,

Response to DR 45 Q 8 and PG&E Report June 20, 2011 p. 6D-4 and P3-30011.

¹⁹⁵ See Testimony of Paul Duller, Records Expert for CPSD in this proceeding.

1 This investigation into recordkeeping issues related to engineering results in two basic
2 conclusions. First, the pipe failure and explosion on Line 132 in San Bruno on September 9,
3 2010 may have been prevented had PG&E managed its records properly over the years. And
4 second, PG&E's entire integrity management program is an exercise in futility because PG&E
5 lacks the basic records necessary to provide fundamental data required for the successful use of
6 the integrity management risk model. Therefore, PG&E has been operating, and continues to
7 operate, without a functional integrity management program.

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ATTACHMENT

577520

Deleted: 101

Margaret Felts

LITIGATION EXPERIENCE AS LEAD TECHNICAL CONSULTANT

2005-2007

LODI GROUND WATER CONTAMINATION
CLIENT: LAW FIRMS REPRESENTING
LLOYDS OF LONDON INSURANCE
COMPANIES INSURANCE, DEFENSE

2000-2002

CALIFORNIA ENERGY CRISES
ENRON INVESTIGATION
PG&E BANKRUPTCY
CLIENT: CA PUBLIC UTILITIES COMMISSION
ENERGY, PLAINTIFF
PLAYA DEL REY GAS STORAGE INTEGRITY,
SoCAL Edison
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIVISION OF RATE PAYER ADVOCATES
ENERGY, PLAINTIFF

2001-2002

BELMONT PROPERTIES
CLIENT: ROPERS
ENVIRONMENTAL, DEFENSE
THREE SISTERS RANCH
CLIENTS: DUANE MORIS & TED HANIG
LAW FIRMS
ENVIRONMENTAL, DEFENSE
AEROJET & LOCKHEED CASES
CLIENTS: MORRIS POLICH & PURLLY,
BERKES, CRANE, ROBINSON & SEAL LLP
INSURANCE, DEFENSE
PG&E POWER OUTAGE, SAN FRANCISCO
DIVISION OF RATE PAYER ADVOCATES
ENERGY, PLAINTIFF

1998-2000

RAYTHEON
GROUND WATER CONTAMINATION
LAW FIRMS REPRESENTING
LLOYDS OF LONDON INSURANCE COMPANIES
INSURANCE, DEFENSE

1998-1999

PG&E TREE TRIMMING CASE
MONTEBELLO GAS STORAGE (SoCAL GAS)
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF
BENZENE EXPOSURE
BARON & BUDD, P.C.
ENVIRONMENTAL, PLAINTIFF

1998-1999

CARPENTER V. CROWLEY MARITIME
BENZENE & ASBESTOS EXPOSURE
WARTNICK, CHABER, ET AL
ENVIRONMENTAL, PLAINTIFF
SCE APP No. 97-12-043
HARBOR COGEN BUYOUT OF LONG TERM
CONTRACT
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES-
ENERGY, PLAINTIFF

1997 - 2002

SKINNER V. ARCO
CLIENTS: TERRY LUMSDEN LAW FIRM
KELLER ROHRBACK L.L.P.
ENERGY/ENVIRONMENTAL, PLAINTIFF

1996-1997

SoCAL GAS V. ASSOCIATED ELECTRIC GAS
INSURANCE COS.
CLIENT: HANCOCK, ROTHERT & BUNSHOFT,
LA
INSURANCE, DEFENSE

1997 - 1998

EXXON V. INA, SUPERFUND CLEANUP
CLAIMS
CLIENT: HANCOCK, ROTHERT & BUNSHOFT,
SF
INSURANCE, DEFENSE

1996 - 1997

DIXIE VALLEY POWER PARTNERSHIP
CONTRACT BUYOUT BY SCE
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

1996-2000

PROCTOR V. LOCKHEED
SOIL AND GROUNDWATER CONTAMINATION
CLIENTS: LAW FIRMS REPRESENTING
LLOYDS OF LONDON INSURANCE
COMPANIES
INSURANCE, DEFENSE

Deleted: 101

577520

1993

TOOLEY OIL V. SNIDER
CLIENT: NAGLEY & MEREDITH, INC.
ENVIRONMENTAL, PLAINTIFF
CLAYTON RD. ASSO INC. V. TEXACO REFINING
& MARKETING INC.
CLIENT: NED ROBINSON
ENVIRONMENTAL, PLAINTIFF
WALSH V. DIABLO MARINE
CLIENT: TURNER, HUGUET, BRANS & ADAMS
ENVIRONMENTAL, PLAINTIFF
TASSAJARA NURSERY V. INSURANCE CO.
CLIENT: NELSON, WARNLOF & VENCILL
INSURANCE, DEFENSE

1992

WISE/WILLIAMS V. BECHTEL
CLIENT: POTTER LAW OFFICES
TORT CASE FOR INJURIES RESULTING FROM
MOHAVE POWER PLANT INCIDENT
ENERGY, PLAINTIFF
PACHECO PROPERTIES V. CHEVRON PIPELINE
CLIENT: TURNER, HUGUET, BRANS & ADAMS
ENVIRONMENTAL, PLAINTIFF
NEVADA POWER V. STATE OF NEVADA
CLIENT: STATE OF NV ATTORNEY GENERAL
OFFICE OF ADVOCATE CUSTOMERS OF THE
PUBLIC UTILITIES COMMISSION
ENERGY, PLAINTIFF

1991-1993

PG&E APPLICATION RE HELMS PUMPED
STORAGE CLAIM
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

1991

SALLE V. RUDD, ET AL
CLIENT: KLAUSCHIE & SHANNON
INSURANCE, DEFENSE

1990

AEROJET GENERAL CORP, ET AL V. ARGONAUT
INSURANCE CO., ET AL
CLIENT: HANCOCK, ROTHERT & BUNSHOFT
INSURANCE, DEFENSE

1988 - 1992

SCE APPLICATION RE MOHAVE COAL FIRED
PLANT STEAM PIPE FAILURE
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

1987-1988

SoCALGAS APPLICATION - CONTRACT
BUYOUT RE MONTEREY LAND PARK LANDFILL
GAS
(OPERATING INDUSTRIES)
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY / ENVIRONMENTAL, PLAINTIFF

1986

SoCALGAS V. FORD, BACON & DAVIS
CLIENT: LAW FIRM REPRESENTING FORD,
BACON & DAVIS
ENERGY, PLAINTIFF

1985

US OF A BEFORE THE FEDERAL ENERGY
REGULATORY COMMISSION RE PACIFIC
OFFSHORE PIPELINE COMPANY, DOCKET NO.
RP85-34-000
CLIENT: CA PUBLIC UTILITIES COMMISSION
ENERGY, PLAINTIFF

1983 - 1985

SoCALGAS, APP NO. 84-09-022 RE PACIFIC
OFFSHORE PIPELINE COMPANY (POPCO) GAS
TREATMENT PLANT
CLIENT: CA PUBLIC UTILITIES COMMISSION,
DIV. OF RATEPAYER ADVOCATES
ENERGY, PLAINTIFF

CAREER HISTORY AND HIGHLIGHTS

PRESIDENT / CFO 2002-2010
CALIFORNIA COMMUNICATIONS ASSOCIATION,
WWW.CALCOM.WS, THE TRADE ASSOCIATION FOR
THE INCUMBENT LOCAL EXCHANGE CARRIERS
SERVING CALIFORNIA (FROM AT&T TO THE
SMALLEST INDEPENDENT RURAL COMPANIES).
IN THIS CAPACITY, I ALSO SERVE AS A VOTING
MEMBER ON THE CA HIGH TECH CRIME
ADVISORY COMMITTEE, AS DEFINED IN
CALIFORNIA STATUTE.

SENIOR CONSULTANT 1995-1997
DAMES & MOORE LEAD CONSULTANT ON
SEVERAL MAJOR ENVIRONMENTAL PROJECTS IN
CALIFORNIA AND WASHINGTON.

DEPUTY DIRECTOR 1993-1995
**CALIFORNIA DEPARTMENT OF TOXIC
SUBSTANCES CONTROL** DIRECTED OVERSIGHT
OF ALL STATE -LEAD NATIONAL PRIORITIES LIST
SITE CLEANUPS IN CALIFORNIA, AND OVER 2,000
STATE LISTED PROJECTS. MANAGED A BUDGET OF
\$326 MILLION, SUCCESSFULLY REORGANIZED AND
COMPLETED HIRING FOR A PROGRAM WITH 312
EMPLOYEES IN 7 CALIFORNIA OFFICE LOCATIONS
IN JUST 1 ½ YEARS. REDUCED OVERHEAD COSTS
AND DRAMATICALLY IMPROVED SERVICE.
ADDRESSED CRITICAL ISSUES AND DEVELOPED
NEW PROGRAM POLICIES IN FULL COORDINATION
WITH THE SITE MITIGATION PROGRAM ADVISORY
GROUP, A GROUP MADE UP OF EXTERNAL
INDUSTRY, ENVIRONMENTAL, AND REGULATORY
REPRESENTATIVES.

DIVISION CHIEF OF ENGINEERING
1985-1990
**DEPARTMENT OF DEFENSE, MCCLELLAN AIR
FORCE BASE**
DESIGNED AND MANAGED DOD'S FIRST PROGRAM
TO IMPLEMENT CERCLA AND THE RESOURCE
CONSERVATION RECOVERY ACT. SUPERVISED 15
ENGINEERS AND TECHNICAL SUPPORT PEOPLE
RESPONSIBLE FOR MANAGING ALL NON-CERCLA
ENVIRONMENTAL LAWS AND REGULATIONS
APPLICABLE TO THE BASE, WHICH WAS A LARGE
INDUSTRIAL COMPLEX EMPLOYING 12,000
CIVILIANS AND MILITARY PERSONNEL. MANAGED
ENVIRONMENTAL PROGRAM BUDGET OF OVER
\$26 MILLION ANNUALLY.

PREVIOUS EXPERIENCE

ENVIORNMENTAL CONTRACTOR
ENERGY SPECIALIST, CALIFORNIA ENERGY
COMMISSION
PROCESS ENGINEER, CELANESE PLASTICS AND
SPECIALTIES
PROCESS ENGINEER, AMOCO OIL COMPANY

EDUCATION

JD, MCGEORGE SCHOOL OF LAW
M.S. ENERGY/ENVIRONMENTAL ENGINEERING,
LASALLE UNIVERSITY
B.S. PETROLEUM ENGINEERING,
LOUISIANA TECH UNIVERSITY
B.A. BUSINESS COMMUNICATIONS,
ECKERD COLLEGE

ADDITIONAL INFORMATION

WASHINGTON STATE BAR # 40507
PHI DELTA PHI INTERNATIONAL LEGAL
FRATERNITY
ASSOCIATE MEMBER, CALIFORNIA BAR
ASSOCIATION
MEMBER, AMERICAN BAR ASSOCIATION
MEMBER, SOCIETY OF PETROLEUM ENGINEERS
NREP REGISTERED ENVIRONMENTAL
MANAGER #2935
CALIFORNIA GENERAL A CONTRACTOR
#757976