

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

Order Instituting Investigation on the
Commission's Own Motion into the Operations
and Practices of Pacific Gas and Electric
Company with Respect to Facilities Records for
its Natural Gas Transmission System Pipelines.

I.11-02-016
(Filed February 24, 2011)

**DIRECT TESTIMONY OF
JOHN GAWRONSKI
ON BEHALF OF
THE CITY AND COUNTY OF SAN FRANCISCO
INVESTIGATION 11-02-016
CALIFORNIA PUBLIC UTILITIES COMMISSION
April 30, 2012**

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1 Q.1 Please state your name and business address.

2 A.1 My name is John Gawronski. I am a consultant affiliated with the Hudson River Energy
3 Group. My business address is 2079 County Route 47, Salem NY 12865.

4 Q.2 Please summarize your education and experience.

5 A.2 I have over 40 years of natural gas pipeline industry expertise in the areas of transmission
6 and distribution pipeline integrity management, pipeline codes and standards, as well as
7 monitoring and regulatory compliance reviews. I hold a BS in Mechanical Engineering
8 and MME in Engineering Management from City College of NY. For the period 1977 –
9 2003 I was Chief of Investigations for the Gas Division, Chief of Safety and Reliability
10 for the Office of Energy & Water, and later Gas & Water for the New York Public
11 Service Commission, supervising a staff of up to 30 employees including senior
12 supervisory responsibility for staff investigations of significant incidents and accidents,
13 and other unusual events, and serving as a senior technical advisor to the Commission
14 primarily on gas matters. I have reviewed the engineering, asset planning and operations
15 of all major New York combination companies and gas utilities. I have evaluated cast
16 iron and steel pipe replacement programs of utility operators and have participated in
17 Transmission Integrity Management Plan reviews and inspections with the USDOT of
18 transmission pipeline operators.

19

20 My resume is included as Exhibit 1.

21 Q.3 On whose behalf are you testifying in this proceeding?

22 A.3 I am testifying on behalf of the City and County of San Francisco (“CCSF” or “San
23 Francisco”).

24 Q.4 What is the purpose of your testimony?

25 A.4 The purpose of this testimony is to identify practices or instances where PG&E’s record
26 keeping represents deficient engineering practice that has fostered unsafe PG&E decision
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28

1 making about its transmission lines and how these record keeping practices have
2 interfered with the regulatory process. The Consumer Protection and Safety Division
3 (“CPSD”) issued two reports on March 16, 2012. The testimony of Duller and North
4 found “[g]as transmission records and safety related documents were scattered,
5 disorganized, duplicated, and were difficult if not impossible to access in a prompt and
6 efficient manner.”¹ The testimony of Margaret Felts addressed how PG&E’s record
7 keeping practices affected PG&E’s pipeline engineering. My testimony complements
8 these two reports and incorporates by reference my testimony submitted on April 23,
9 2012 in Investigation (“I.”) 12-01-007.

10
11 While many violations are framed in terms of failure to comply with federal regulations,
12 the underlying actions also constitute violations of PG&E’s obligation to furnish such
13 service “necessary to promote the safety, health, comfort, and convenience of its patrons,
14 employees, and the public.”²

15
16 Q.5 What materials did you review in preparing this testimony?

17 A.5 I reviewed the National Transportation Safety Board Report (“NTSB”) Accident Report
18 dated August 30, 2011, the Independent Review Panel report dated June 24, 2011, the
19 CPSD Incident Investigation Report into the San Bruno rupture dated January 12, 2012,
20 the CPSD reports issued in CPSD’s investigation into PG&E’s record keeping practices
21 dated March 12, 2012, PG&E’s annual transmission reports to USDOT for 2008 and
22 2009, PG&E’s response to data requests from various parties and other materials made
23 available to the public, and portions of the transcripts from the March 2012 hearings in
24 the gas safety rulemaking.

25 Q.6 Can you summarize your testimony?

26 _____
27 ¹ Testimony of Duller and North, at p. 1-10.

28 ² Cal. Pub. Util. Code § 451.

1 A.6 Yes. When the grandfathering provision was enacted in 1970, there was an expectation
2 that pipeline operators would have pressure test records to substantiate their pipelines'
3 historic maximum operating pressure. There was also an understanding that certain
4 levels of safety were being provided by means of class location design factors that limited
5 the maximum pressure based on test pressures and the population density of the route
6 along the pipeline. The Department of Transportation believed operators had a working
7 knowledge of the requirements of the industry safety code ANSI B31.8 applicable to gas
8 pipelines and had applied these requirements to their design, construction and operating
9 practices.

10
11 The investigations and rulemaking following the San Bruno pipeline failure have found
12 that numerous records concerning the basis for PG&E's maximum operating pressures
13 and code compliance activities are unaccounted for, misplaced or just missing. For
14 example, pressure test records for many pipelines are missing and instead statements
15 about operating pressures (and not actual test pressure charts and related test pressure or
16 operating pressure documents) form the basis for establishing maximum pressures.

17
18 Further, certain records and reports may not have been available for review when
19 important safety evaluations were being made and when safety process steps were being
20 taken. PG&E's record keeping appears to have prevented it from considering relevant
21 weld defect documents in its Transmission Integrity Management Program ("TIMP").
22 CPSD witness Felts identified how PG&E's poor record keeping contributed to re-used
23 pipe being used for segment 180 of Line 132 and how the grandfathered MAOP for Line
24 132 was changed based on conflicting records. The disorganization identified by CPSD
25 witnesses Duller and North appears to extend to PG&E's organization of the documents
26 governing its TIMP procedures.

27 Q.7 Do you know why the Commission instituted this investigation?

1 A.7 This proceeding was opened to “assess PG&E’s compliance with the law pertaining to
2 safety-related record keeping for natural gas transmission pipelines.”³ The Commission
3 responded to the NTSB’s January 3, 2011 urgent recommendations and inferred that “the
4 state of PG&E’s records regarding critical infrastructure (in particular, its high-pressure
5 gas transmission pipelines) may have been inadequate to make critically important
6 ongoing safety decisions about PG&E’s natural gas transmission pipelines, particularly
7 welded pipelines.”⁴ The purpose of this investigation is to determine “whether PG&E’s
8 record keeping represents a deficient engineering practice that has fostered unsafe PG&E
9 decision making about its transmission lines. ... and decide whether PG&E’s record
10 keeping pertaining to its gas transmission lines, including San Bruno, has violated good
11 and accepted engineering standards and practices, and thus whether PG&E violated
12 Section 451 of the Public Utilities Code or other laws and regulations.”⁵

13 Q.8 How is the grandfathering provision related to record keeping?

14 A.8 The grandfather provision was introduced when the federal minimum safety regulations
15 were enacted in 1970. The federal register published on August 19, 1970 includes an
16 extensive discussion on the purpose of the grandfathering provision. Initially, the
17 Department of Transportation proposed a rule that would have required MAOP to be
18 determined by the lower of either (1) the design pressure in the weakest element in the
19 pipeline system, or (2) the pressure obtained by dividing the pressure to which the
20 pipeline was tested after construction by the appropriate class location factor.⁶ The
21 Department of Transportation, however, recognized “since some pipelines have been
22 operated above 72 percent of specified minimum yield strength (the highest design stress
23 allowed by Part 192) and since many were tested to no more than 50 pounds above

24 ³ Order Instituting Investigation on the Commission’s Own Motion into the Operations and
25 Practices of Pacific Gas and Electric Company with Respect to Facilities Records for its Natural
26 Gas Transmission System Pipelines, at p. 1.

26 ⁴ *Id.*, at p. 8.

27 ⁵ *Id.*

27 ⁶ 35 Federal Register 13248 (August 19, 1970) (Exhibit 1).

1 maximum allowable operating pressure, these proposed regulations would have required
2 a reduction of operating pressures” for those pipelines to comply with the new
3 regulations.⁷

4
5 After the Department of Transportation proposed the regulations in 1968 in draft form,
6 the Federal Power Commission submitted a letter stating that the proposed new
7 requirements would require operators to reduce the pressure on “thousands of miles” of
8 pipeline installed between 1935-1951 because many pipelines installed during those years
9 in compliance with the then existing codes, were only tested to 50 psi above the
10 proposed maximum operating pressure.⁸ The Federal Power Commission stated that it
11 had “reviewed the operating record of the interstate pipeline companies and found no
12 evidence that would indicate a material increase in safety would result from requiring
13 wholesale reductions in the pressure of existing pipelines which have proven capable of
14 withstanding present operating pressures through actual operation.”⁹ The Federal Power
15 Commission concluded “[i]f it is the intention of the Office of Pipeline Safety to require
16 the retesting of all existing pipelines to the higher standards proposed ... it is our
17 suggestion that this section be revised to permit the development of an orderly testing
18 program that will allow the jurisdictional pipeline companies the necessary time to obtain
19 from this Commission such certificate authorizations as may be necessary.”¹⁰

20
21 In response, the Department of Transportation stated “in view of the statements made by
22 the Federal Power Commission, and the fact that this Department does not now have
23 enough information to determine that existing operating pressures are unsafe, a
24 “grandfather” clause has been included in the final rule to permit continued operation of

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26 ⁷ *Id.*
27 ⁸ *Id.*
⁹ *Id.*
¹⁰ *Id.*

1 pipelines at the highest pressure to which the pipeline had been subjected during the 5
2 years preceding July 1, 1970.”¹¹

3
4 Q.9 What do you infer from these statements in the federal register?

5 A.9 These statements identify principles underlying the Department of Transportation’s
6 safety regulations approach: first, that when the Department of Transportation enacted the
7 regulations, it expected that operators would have detailed records of its pipe and
8 components to either be able to calculate MAOP based on the weakest element in the
9 pipeline system, and that operators would have pressure test records to validate the
10 MAOP. Second, that the Department of Transportation allowed grandfathered pressures
11 because it assumed the pipelines that would operate pursuant to the grandfather clause
12 would primarily be those pipelines that:

- 13 • had been installed from 1935 to 1951; and
- 14 • either applied lower class location design factors than the industry applied since
15 1952 up until the 1968,¹² or
- 16 • only been tested to 50 psi above the MAOP.

17 In other words, the Department of Transportation assumed that operators would have
18 pipeline design, construction, operating history, material and component records and
19 pressure test records to validate the integrity of the pipeline to at least 50 psi above the
20 MAOP of the line. Older pipelines installed before 1935 would be limited to actual
21 pressures experienced within a more recent 5 year defined period (1965-70). The
22 Department of Transportation reasoned that this would prevent an operator from using a
23 theoretical maximum operating pressure which may have been determined under some
24 formula used 20, 30, or 40 years ago (prior to 1970).

25
26 ¹¹ *Id.*

27 ¹² The requirements of the 1968 ANSI B31.8 code was being essentially implemented as interim
28 federal safety standards following enactment of the US Natural Gas Pipeline Safety Act of 1968.

1
2 These facts are relevant because the grandfather provision is based on the assumption that
3 an operator had records of its pipeline materials as well as pressure test records to
4 validate the historic MAOP, and the fact that the Department of Transportation could not
5 determine that the historic pressures were unsafe. If the operators lacked pressure test
6 records and the operator could not determine the MAOP based on the weakest element, it
7 is doubtful that the Department of Transportation would have considered the historic
8 operating pressure to be safe.

9 Q.10 Are there ways an operator can establish a historic MAOP under 192.619(c) other than
10 records that empirically substantiate the historic maximum operating pressure?

11 A.10 Yes, in order to accommodate operators that may be missing pertinent records, an
12 operator may use a notarized affidavit to determine the historic MAOP. Although this
13 method of determining historic MAOP may be acceptable at the discretion of regulatory
14 agencies, using a notarized statement in lieu of pressure charts or inspection reports
15 increases the level of uncertainty associated with gas pipeline operations.

16 Q.11 Does PG&E use affidavits to establish the historic MAOP for its pipelines?

17 A.11 Yes. In the hearings on PG&E's Pipeline Safety Enhancement Plan, PG&E's witness
18 stated that of its pipelines located in high consequence areas operated pursuant to the
19 grandfather clause, the MAOP for 50-70% of those pipelines is established by affidavit.¹³

20 Q.12 Is this common in the industry?

21 A.12 No. As I described in my testimony in Investigation 12-01-007, using notarized
22 statements to establish the MAOP for any pipelines is the exception. In my 40 plus years
23 of experience working in the gas industry and as a gas safety regulator, I have
24 participated in audits of pipelines operating in many states and reviewed the basis for
25 MAOPs of pipelines. I have not seen any pipelines where the MAOP was determined by
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27 ¹³ OIR 11-02-019, Reporter's Transcript, March 23, 2012 Volume 12 1612:2-1613:12.

1 historic affidavits under the grandfather provision. Only on a few occasions, through
2 word of mouth from other State regulators have I even heard that an operator would
3 determine its MAOP based on an historic affidavit. Usually, these circumstances would
4 not be applied to transmission pipelines in populated locations.

5
6 The fact that PG&E used affidavits to establish the MAOP for the majority of
7 grandfathered pipelines located in high consequence areas is unusual and a reflection on
8 the state of PG&E's records. If PG&E had to use affidavits to establish the historic
9 MAOP, it should have taken extra precautions to ensure the integrity of its pipeline
10 system. As discussed earlier, when the grandfather provision was enacted it was intended
11 to avoid having to *re-test* lines that did not meet current class location design limits or
12 had only been tested to 50 psi above MAOP. It was not intended to be used as *carte*
13 *blanche* for operators lacking important pipeline records.

14 Q.13 Did the CPSD report make any findings regarding record keeping issues affecting Line
15 132?

16 A.13 Yes. CPSD witness Felts many made findings regarding how PG&E's record keeping
17 practices affected its pipeline operations, including how PG&E's poor record keeping
18 contributed to re-used pipe being used for segment 180 of Line 132, and how the
19 grandfathered MAOP for Line 132 was changed based on conflicting records.¹⁴

20 Q.14 Are there additional facts that are relevant to the CPSD report's analysis?

21 A.14 Yes. PG&E recently produced a document showing that Line 132 had suffered a seam
22 failure in 1989. I described this report and its significance in my testimony submitted in
23 Investigation 12-01-007.

24 Q.15 Can you briefly describe the report?
25

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27 ¹⁴ Testimony of Felts, at pp. 2-3.

1 A.15 On March 1, 1989, PG&E’s Technological and Ecological Services sent a memorandum
2 which stated that a 30” section of Line 132 had been “removed for failure analysis
3 because of a pinhole leak in the longitudinal seam weld.”¹⁵ The memorandum finds that
4 “[o]verall, the x-ray inspection showed the weld to be of low quality, containing
5 shrinkage cracks and voids, lack of fusion, and inclusions. Although the actual leak
6 could not be found, it is likely that it was related to one of the weld defects.”¹⁶ The
7 memorandum also states that “the cracks are pre-service defects, i.e. they are from the
8 original manufacturing of the pipe joint.”¹⁷

9
10 PG&E should have reviewed this document in the context of its integrity management
11 program, and then evaluated all similar pipeline for potentially unstable manufacturing
12 and construction defects under the data gathering and integration procedures of section
13 192.917(b) and the analysis of the data required by the TIMP regulations. The report
14 should also have raised concern that PG&E’s quality control procedures were deficient at
15 the time the pipe segment was installed in 1948.

16
17 Q.16 Has PG&E had difficulty producing documents in this proceeding?

18 A.16 Yes. As a general matter, PG&E has been unable to produce documents requested by the
19 Commission in a timely fashion. On June 3, 2011, the Commission’s Legal Division
20 filed a prehearing conference statement in which it withdrew a request that PG&E:

21 “Organize and produce, on a pipeline segment by pipeline segment basis,
22 for each and all of PG&E’s transmission pipelines, the following data and
23 documents:

- 24 • All as-built drawings, documents, photos
- 25 • All pipe specifications, manufacturer’s operating manuals,
- 26 • and instructions
- 27 • All operating history of the pipe, including but not limited to

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¹⁵ 1989 TES Memorandum (Exhibit 2, p. 8)

¹⁶ *Id.*

¹⁷ *Id.*

- pressure.
- All maintenance and repair history of the pipe
- All risk assessment done of the pipe”¹⁸

The Legal Division asserted that the reason for withdrawing the request was that “PG&E would spend months or years reorganizing its documents in the way requested in the data request.”¹⁹ In other words, PG&E did not have the relevant information already organized on a segment by segment basis.

Specific to documents concerning weld failure, the prehearing conference statement noted “PG&E has requested additional time to respond to the Commission’s directive for PG&E to provide weld failure and flaw information. PG&E asks permission to provide the data on a rolling schedule from September 20, 2011 to sometime at the end of 2012. PG&E’s request itself demonstrates just how abysmal its recordkeeping is. PG&E is required by law to consider weld defects and failures for its pipeline integrity program.”²⁰

Six months later, the ALJ in this proceeding even noted that the delay reflected poorly upon PG&E’s record keeping practices.

“it is troubling that PG&E is apparently unable to respond to Legal Division’s data requests in a timely manner. In this proceeding, PG&E has sought and been granted numerous extensions to provide responsive documents. While I recognize that the Commission and Legal Division have requested that PG&E provide a substantial amount of documents, many of these documents are required to be maintained under federal and state statutes and regulations. As such, it is unclear why PG&E is unable to provide these documents in a timely manner.”²¹

As I described in my testimony in I.12-01-007, PG&E is required to consider the failure history on its pipelines, including weld failure documents pursuant to TIMP regulations and I support the ALJ’s concern. To comply with the TIMP regulations, PG&E needed a

¹⁸ Legal Division Prehearing Conference Statement, filed June 3, 2011, at p. 1.

¹⁹ *Id.* at p. 2.

²⁰ *Id.* at p. 3.

²¹ Administrative Law Judge’s Ruling Granting, In Part, Motion For Extension Of Time And Revising Schedule For Proceeding, issued December 22, 2011, at p. 2.

1 methodology to integrate data so that it could evaluate the potential risks to the pipelines.
2 The method chosen should have allowed PG&E to gather and integrate existing data and
3 information on the entire pipeline that could be relevant to covered segments.²² PG&E is
4 required to verify that the necessary pipeline data have been assembled and integrated.
5 At a minimum, PG&E should have evaluated and gathered for each segment information
6 on the operation, maintenance, patrolling, design, operating history, and specific failures
7 and concerns unique to each system and segment.²³

8
9 Basic elements of proper data integration and evaluation include: storage, retrieval,
10 granularity, collection, aggregation, and integration.²⁴ Data integration consists of more
11 than simply putting several types of information into a single location. “The most
12 important aspect of data integration is the analysis of aggregated data in order to discern
13 integrity threats and risks that would not otherwise be observed from independently
14 reviewing the various individual data elements.”²⁵ Based on findings in my testimony in
15 I.12-01-007 that PG&E did not seriously consider manufacturing and construction
16 defects, it appears that PG&E did not adequately perform this analysis as required.

17
18 In addition, based on the findings in the testimony of Duller and North that PG&E’s
19 “pipeline records were widely distributed and poorly controlled,” that PG&E lacked
20 “necessary document control processes ... to track [the] location, existence or contents [of
21 the records],”²⁶ that PG&E’s records were inaccurate,²⁷ and PG&E’s difficulty in

22
23 ²² 192.917(b).

²³ PHMSA Inspection Protocols with Supplemental Guidance; section C.02.b. The protocols are available publicly at:

24 [http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/GasIMP%20Protocols%20With%20Guidance%20\(8%201%202008\).w.disclaimer.pdf](http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/GasIMP%20Protocols%20With%20Guidance%20(8%201%202008).w.disclaimer.pdf)

25 ²⁴ *Id.*

²⁵ PHMSA Inspection Protocols with Supplemental Guidance; section C.02.a. (emphasis in original).

26 ²⁶ Testimony of Duller and North, at pp. 1-7.

27 ²⁷ *Id.* at p. 1-10.

1 producing the documents in this proceeding, it appears that PG&E did not have a
2 consistent, repeatable basis for gathering and integrating accurate data. PG&E was
3 required to have procedures that considered these types of documents to identify and
4 evaluate the potential threats to its pipelines.

5 Q.17 Are there other examples where PG&E's record keeping practices have interfered with
6 the regulatory process?

7 A.17 Yes. As part of its investigation, the NTSB asked PG&E to "[p]lease provide a listing of
8 all other pipelines, along with corresponding dates, SCADA printouts, and pressure
9 charts, where PG&E has applied its practice of reestablishing MAOP every 5 years as
10 PG&E has indicated it has done on Line 132. Please provide copies of all policies,
11 standards, procedures, etc. related to PG&E's practice of reestablishing MAOP on its
12 pipelines."²⁸ In response, PG&E asserted that it spiked the pressures on its lines "to
13 avoid [pressure testing] and any potential customer curtailments that may result," and
14 therefore "PG&E has operated, within the applicable five-year period, some of its
15 pipelines that would be difficult to take out of service at the maximum pressure
16 experienced during the preceding five-year period in order to meet peak demand and
17 preserve the line's operational flexibility."²⁹ PG&E also attached a copy of Risk
18 Management Instruction, ("RMI-06") "which describes PG&E's process to increase
19 pressure in certain transmission lines every five years for these operational purposes."³⁰
20

21 Following the NTSB hearings in early March, PG&E submitted a letter to the NTSB and
22 the CPUC explaining that "the version of PG&E's RMI-06 which PG&E submitted to the
23 NTSB and became NTSB Exhibit No. 2-AG included the cover sheet approval for RMI-
24

25 _____
26 ²⁸ PG&E's Amended Data Response, NTSB Exhibit 2-AI of the San Bruno Investigation
(Docket No. SA-534) (Exhibit 3).

27 ²⁹ *Id.*

28 ³⁰ *Id.*

1 06 revision 0 but attached the text for RMI-06 draft revision 1.”³¹ With that letter, PG&E
2 stated “[t]he approved RMI-06 (Rev. 0) at the time of our original submission is enclosed
3 along with the currently-effective RMI-06 (Rev. 1). Neither of them includes the 10
4 percent provision found in the unapproved version.”³²

5
6 PG&E is required to establish these types of risk management procedures to comply with
7 TIMP requirements. These procedures must be maintained such that they are readily
8 retrievable, protected from damage, and secured sufficiently to prevent unauthorized
9 changes. Gas pipeline operators should keep procedures as well as records in a formal or
10 structured record-keeping system, as opposed to individual working files.

11
12 Further, any changes to procedures, gas system, or gas operations, must follow a formal
13 documented management of change process. Pursuant to the TIMP regulations, “an
14 operator must document *any* change to its program and the reasons for the change before
15 implementing the changes.”³³ This means that earlier revisions to the program should be
16 included in document files as archived information, and operators should include
17 evidence as to why any program documents have been revised and the effective date of
18 the revisions. If no documentation exists to describe and justify the change, then the
19 operator is not properly managing the change.

20
21 The confusion created by “draft revision 1” shows that PG&E has not properly managed
22 the records to identify changes to its TIMP. It shows that PG&E lost version control over
23 a key document related to its pipeline integrity management, and that PG&E was unable
24 to prevent the dissemination of unauthorized versions of its risk management procedures.

25
26 ³¹ NTSB Revised Exhibit 2-AG Overpressurization Requirement RMI-06 Rev 00 and Rev 1
(Exhibit 4).

27 ³² *Id.*

28 ³³ 192.909(a) (emphasis added).

1 It is also unclear how the cover sheet from revision 0 was attached to a “draft revision 1,”
2 or why the word DRAFT does not appear anywhere on “draft revision 1.”

3 Q.18 Do you have any other concerns related to PG&E’s RMI-06?

4 A.18 Yes. The face sheet to RMI-06 revision 0 shows that it was first prepared and approved
5 in 2008. This would indicate that PG&E did not have a procedure in place to monitor
6 pressures or prevent MOPs from over-pressurization before 2008. This supports
7 statements in my testimony submitted in Investigation 12-01-009 that PG&E did not
8 adequately monitor the pressures on its pipelines prior to 2008. Because PG&E lacks
9 records of the pressures on its pipelines prior to 2008, PG&E would have been unable to
10 evaluate key safety factors: whether the pressures on its pipelines have exceeded the five-
11 year MOP or the MAOP of the pipeline; justification for whether the manufacturing and
12 construction threats on its lines should be considered stable; the impacts from cyclic
13 fatigue on its pipelines; or the extent of interactive threats on its pipelines.

14 Q.19 Do you have any conclusions?

15 A.19 Yes. The facts identified above do not support a finding that PG&E’s record keeping
16 practices adhered to sound engineer principles. Specifically:

- 17 • Because PG&E lacked adequate records it was required to over-rely on the
18 grandfathering provision (and specifically affidavits of historical operating
19 pressures) to substantiate the MAOP for its pipelines;
- 20 • PG&E had conflicting records to establish the MAOP for Line 132;
- 21 • PG&E’s record keeping practices failed to prevent old pipe from being re-used,
22 and failed to track old pipe that was re-used;
- 23 • PG&E’s record keeping practices appear to have prevented it from adequately
24 considering weld defect documents evidencing unstable manufacturing and
25 construction defects; and
- 26 • PG&E’s management of change procedures did not properly track revisions of
27 key integrity management documents.

1 Q.20 Do you have any minimum recommendations for PG&E's record keeping systems?

2 A.20 Yes.

- 3 • PG&E's record keeping system should act as a central repository server housing
4 all technical documents. To ensure accountability, gatekeepers for each type of
5 document should be identified;
- 6 • PG&E should identify the types of associated programs needed to access those
7 documents;
- 8 • To assist in the analysis and integration of the data, PG&E's GIS system should
9 be capable of providing maps, on a segment by segment basis, that provide a
10 visual layering (beneath the plan view of the pipeline) of key IMP attributes;
- 11 • To further assist in the analysis and integration of key attributes, the GIS system
12 should have links to key documents in the central repository. This will assist
13 individuals in accomplishing their assigned duties and responsibilities;
- 14 • The systems provide for access by program engineers and technicians to pull up
15 historical documents related to materials, welding, cathodic protection, leak
16 history, any field inspection reports or metallurgical analyses reports, ILI results,
17 and historical pressure testing and DA inspections performed;
- 18 • The system should identify the individuals responsible for accomplishing and
19 documenting key analyses required by PG&E's procedures;
- 20 • When issues requiring follow-up, sign off or approvals are identified, the system
21 should be capable of allowing ready identification of the status of any of the
22 procedures or IMP process steps;
- 23 • The system should identify when key responses to process steps are pending, and
24 should have the capability of receiving updated interim and final reports and
25 analyses to keep the systems current and filed within the central repository;
- 26 • A documented management of change process should be included in the platform
27 and central repository to ensure any change to key pipeline attributes and process
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1 steps are managed and so all key individuals are advised of changes and included
2 in the process.

3 Q.21 Does that conclude your testimony?

4 A.21 Yes, it does.

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