PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

RECORD RETENTION REQUIREMENTS AND PRACTICES

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RECORD RETENTION REQUIREMENTS AND PRACTICES

The Duller/North Report criticizes PG&E's records retention standards and practices. Its findings and supporting analyses are scattered across three appendices (Appendices 3, 8, and 9) and several different report sections (6.2.3, 6.3.1, and 6.3.2). Collected together, these findings purportedly support the violations asserted in the Duller/North Supplement.

The Duller/North Supplement asserts a general records management violation (A.1), portions of which touch on records retention topics. In slightly more concrete terms, the Supplement asserts six records retention violations (B.1-B.6) across a varied range of time frames.[1] These six records retention violations are:

1. PG&E's alleged minimal compliance with some of its own retention policies regarding leak survey maps violates others requirements (April 2010 to September 2010).
2. PG&E's alleged minimal compliance with some of its own line patrol report retention policies violates other requirements (dates ranging from September 1964 to September 2010).
3. PG&E's alleged minimal compliance with some of its own line inspection report retention requirements violates other requirements (1994 to September 2010).
4. PG&E's alleged minimal compliance with some of its gas high pressure test record retention polices violates other requirements (1994 to September 2010).
5. PG&E's alleged minimal compliance with some of its record retention policies of transmission line inspections, including patrol maintenance reports, trouble reports and line logs, violates other requirements (dates ranging from September 1964 to April 2010).
6. And, the allegation that at all times between 1955 and 2010, PG&E was aware of the requirement to retain and maintain certain documents for various lengths of time but failed to fully implement the required practices (dates ranging from 1955 to September 2010).

Ms. Felts adds a record retention violation of her own (Violation 17), which relates to PG&E's alleged failure to retain Pipeline History Files (1987 to 2010).[2]

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[1] Duller/North Report at 6-34 – 6-36 and Appendix 9; Duller/North Supplement at 3-4 (Violations B.1-B.6).

[2] Felts Supplement at 12.

Chapter 2 responds to these alleged records retention violations (both the general (A.1) and more specific.[3] It has two parts. Part A summarizes key features of PG&E's historic records retention standards and practices. We reconstruct historic retention standards and key developments in PG&E's records storage processes. Because of the passage of time, this testimony draws mainly from historic documents describing these standards and events. This part also addresses the contention that PG&E failed to maintain Pipeline History Files.

In Part B, Ms. Dunn evaluates the sufficiency of CPSD's analysis that underpins the general records retention violation (A.1) and the six specific ones (B.1-B6). Ms. Dunn shows that the Duller/North Report includes numerous mistakes and unsupported assumptions that undermine the bases for its asserted violations.

[3] Duller/North at 3-4 (Violations B.1-B-6); Felts Supplement at 12 (Violation 17).

CHAPTER 2A

OVERVIEW OF PG&E'S RECORDS RETENTION STANDARDS AND PRACTICES

PG&E has had some form of records retention program in place since at least 1938. As discussed below, the program has at various times included detailed retention and disposal requirements (hereafter, "standards") and retention schedules, which were revised and refreshed to reflect regulatory changes and operating needs. The program has had some (albeit basic) audit and oversight features. It has taken into account how records were used and stored within the Company's different organizations.

And, as further discussed below, PG&E's records retention practices reflected operating realities. Looking backward, PG&E gave thought to legal, regulatory, fiscal, operational, and historic requirements of the kinds specified in the GARP Principle of Retention. Beginning in the 1950s, if not earlier, PG&E – like other large companies – was burdened with growing volumes of paper records that were costly to store and many of which were no longer useful. It expanded records storage facilities, automated indexing systems, communicated with the Commission about regulatory inconsistencies, and studied storage options and alternatives. PG&E's records retention and disposal standards and schedules evolved in response to these records challenges in ways that took account of changing regulatory requirements and operating needs.

1. Standards and Procedures

At a corporate level, PG&E's records retention standards evolved across four successive generations, as summarized in the table below:

TABLE 2A-1
PACIFIC GAS AND ELECTRIC COMPANY

First Generation	December 8, 1938 Letter (Ex. 2-1) and Circular Letter Ex. #642 (Ex. 2-2)	Effective Period: 1938 – 1959
Second Generation	The Standard Practice (SP) 210.4 Series (210.4-1 through 210.4-5) (See, e.g., Ex. 2-3)	Effective Period: 1959 – 1996
Third Generation	Utility Standard Practice (USP) 4 (See, e.g., Ex. 2-4)[4]	Effective Period: 1996 – 2010
Fourth Generation	GOV-7001S (Ex. 2-5)	Effective Period: 2010 to present

These standards, and many of their revisions, were submitted to the Commission as part of the June 20, 2011 filing and appear in the Index to Chapter 2A at ranges P2-191 through P2- 233.

2. PG&E Maintained Records Retention Standards and Schedules

PG&E has long provided records retention guidance to its business units.[5] The oldest records retention document located in the course of this proceeding is a letter dated December 8, 1938, from the Company's Vice President and General Manager to the Heads of Departments and Division Managers. (Ex. 2-1.) The letter enclosed a copy of the Federal Power Commission (FPC) "Regulations to Govern the Preservation of Records of Public Utilities and Licensees – Effective August 1, 1938," and instructed the Departments and Divisions to maintain records in accordance with the regulations.

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[4] From 1996 to 1998, the first iteration of the third generation was named Corporate Standard Practice (CSP) 4. (Ex. 2-6.) Upon its scheduled revision date in 1998, the name was changed from "Corporate" to "Utility" to make it clear that the standard applied only to Pacific Gas and Electric Company, and not the holding company, PG&E Corporation, which was formed after the standard was issued.

[5] PG&E retains correspondence with the Commission (then the Railroad Commission of the State of California) regarding the retention and disposal of records that dates to 1915.

Similarly, a circular letter dated May 17, 1951 (Circular Letter Ex. #642) originated from the Company's Vice President and General Manager and was addressed to the Heads of Departments and Division Managers.[6] (Ex. 2-2.) It enclosed a copy of the FPC "Regulations to Govern the Preservation of Records of Public Utilities and Licensees," effective August 1, 1938, with amendments to January 1, 1951. PG&E's files include a copy of 1924 record retention regulations from the Commonwealth of Massachusetts, suggesting that as early as the 1920s, the Company was abreast of records retention discussions.[7]

Over time, PG&E's guidance included standards and retention schedules, or allowed for the development of such schedules.[8] The original SP 210.4-4 (governing records in the Divisions) included a retention schedule for the Divisions to use. (Ex. 2-8, at GTR0004114.) Later, the Company delegated responsibility to the Divisions (then referred to as "Operating Regions") to develop their own schedules, but in doing so made the Company's Supervisor of Records responsible for providing "staff assistance to all Regions in all matters pertaining to to [*sic*] records retention, destruction, methods and procedures, housekeeping practices, space layouts, equipment, and other areas of the records management fields." (SP 210.4-4 (eff. 6/1/86) (Ex. 2-9, at GTR0004210, GTR0004213).) Similarly, the original SP 210.4-3 (governing records in the General Office Departments) delegated to the Departments the authority to devise their own schedules. (Ex. 2-3, at GTR0004111.) When originally promulgated in 1959, SP 210.4-3 provided the Departments with an exemplar schedule to use to guide their efforts, and advised Departments that they could seek the assistance of a Records Management Consultant.

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6 PG&E previously provided Circular Letter Ex. #642 as part of its June 20, 2011 filing. (P2-191.)

7 Commonwealth of Massachusetts Department of Public Utilities, *Regulations to Govern the Destruction of Records of Gas, Electric and Water Companies and of Municipal Lighting Plants* (Jan. 1, 1924). (Ex. 2-7.)

8 As explained in Chapter 2A of PG&E's June 20, 2011 filing, historically PG&E used different names for different types of guidance documents, including: Policies, Standards, Design Standards, Guidelines, Work Procedures, Bulletins, Forms and Manuals. Beginning in July 2010, PG&E began a gradual process to convert many of these documents to a standardized naming convention, format, content, and organization. (June 20, 2011 filing at 2A-4, n.1.)

In a more recent era, the Company looked to the General Office Departments and the Divisions to assist in developing records retention guidance. (SP 210.4-3 (eff. 4/1/94) (Ex. 2-10).) These standard practices allowed each line of business to supplement, modify, or delete their respective retention schedules as they believed to be appropriate, in compliance with applicable regulations. (Ex. 2-10, at GTR0004258.) The resulting schedules grouped records into categories of documents (e.g., Accounting, Human Resources, Operations and Maintenance, etc.) and provided guidance that drew from numerous regulatory sources, for example, 18 C.F.R. Parts 125 and 225, promulgated by the FPC (later known as the Federal Energy Regulatory Commission (FERC)) and Commission Resolution FA-570 (1976). (Guide to Retention of Company Documents (Apr. 6, 1994) (Ex. 2-11); Guide to Record Retention (Mar. 14, 2005) (Ex. 2-12); Guide to Record Retention (May 22, 2008) (Ex. 2-13).)

The trend of allowing the Departments and Divisions to develop their own retention schedules continued throughout PG&E's "third generation" of records retention standards – *i.e.*, the USP 4 series. (See, e.g., Ex. 2-4.) PG&E's applicable governing standard today, GOV-7001S, similarly does not provide a schedule for record retention; rather, it is an overarching records retention policy that continues to allow each line of business to develop its own records retention schedules. (Ex. 2-5.) Several Departments, including gas, post their retention schedules on a centralized PG&E intranet site.

PG&E revised and refreshed the retention standards and schedules to reflect contemporaneous changes in regulatory requirements. The Company transmitted Circular Letter Ex. #642 to the Departments and Divisions in 1951 to alert them to changes made through the FPC's 1951 amendments. (Ex. 2-2.) Between 1959 and 1996, the SP 210.4 series of standards was revised numerous times. Many of those revisions either refreshed the retention schedules or standards themselves, or alerted Departments and Divisions to the regulatory changes. The 1964 retention schedule that PG&E provided to its Divisions (Ex. 2-14) followed the Commission's adoption in 1962 of amendments to the FPC's records retention regulations.

PG&E's retention schedules also became more sophisticated over time. The 1964 retention schedule for the Divisions was basic. It consisted of an alphabetical listing of records types and associated retention periods with minimal effort to justify the retention periods or define the scope of different categories of records. (Ex. 2-14.) In contrast, by 1994, the Company's retention schedule was categorized by topic – e.g., Accounting & Corporate Records, Human Resources, Electric Supply, Gas Supply, Nuclear Power Generation, etc., and broke down records into specific sub-categories. (Ex. 2-11). For example, whereas the 1964 schedule contains a single entry for "Line Inspection Reports" (Ex. 2-14, at GTR0004135), the 1994 schedule contains two entries: one for for "Electric Transmission & Distribution" and one for "Gas Transmission & Distribution" (Ex. 2-11, at GTR0004316). The same is true for "Line Patrol Reports."

Technological innovations influenced how PG&E stored records. As innovations like microfilm storage emerged as an alternative to paper, PG&E periodically refreshed its definition of a "record" to keep pace. For example, by 1994, SP 210.4-3 (eff. 4/1/94) defined "Records" as "all memoranda, documents, correspondence, and other materials, whether in written, microfilm, microfiche, or <u>*computer media form*</u>." (Ex. 2-10, at GTR0004258 (emphasis added).) Similarly, by 1996, CSP 4 (issued 7/1/96) added "video" and "audio" to the definition. (Ex. 2-6, at GTR0004334.) By 1998, USP 4 (issued 10/22/98) defined "Records" as "all memoranda, documents, correspondence, or <u>*other forms of tangible information storage*</u> (including photographs, microfilm, microfiche, <u>*video tapes*</u>, <u>*electronic media*</u>, <u>*sound recordings*</u>, etc.)." (Ex. 2-4, at GTR0004340 (emphasis added).)

3. PG&E Corresponded with the Commission About Inconsistencies and Uncertainties That Had Arisen in Retention Requirements

Between 1951 and 1976, the Company's retention standards and schedules placed particular emphasis on FPC/FERC records retention provisions contained in 18 C.F.R. Part 125 and Part 225. So did the Commission. During the 1950s and 1960s, the Commission periodically adopted the FPC records retention regulations and made them applicable in California without taking into account other records retention requirements in the Commission's own General Orders including, by 1961, General Order 112.[9] This dichotomy persisted until 1974, when Commission staff (specifically the Finance and Accounts Division) observed a "variance between the revised FPC regulations and the Commission's General Orders" and proposed a new Resolution (FA-554) to address the variance.

CPUC Resolution No. FA-554, issued in 1974, was the Commission's first attempt to reconcile the FPC (by then called FERC) records retention regulations with those that appeared in the Commission's General Orders, including GO 112-C. (Nov. 4, 1974 CPUC Letter (Ex. 2-18).) But it was not long before PG&E recognized that FA-554 had itself introduced a number of uncertainties and inconsistencies. In June 1975, PG&E wrote to the Commission, explaining in part:

> However, in some specific instances enumerated by the resolution [*i.e.*, CPUC Res. No. FA-554], records covered by certain General Orders were assigned retention periods that would apply in lieu of the otherwise applicable FPC rule. Recognizing that this formulation of retention regulation could cause uncertainty, PGandE set about a study to determine exactly what retention periods should be applied to all Company records to assure compliance with the CPUC and FPC regulations to which it is subject.
>
> The results of this study are disturbing. A number of uncertainties and inconsistencies appear which cannot be resolved by the general provisions of Resolution No. FA-554. Without attempting to be exhaustive, a number of examples have been collected, and are outlined in the two-page Appendix B attached hereto. On these and similar record retention questions PG&E is in need of further guidance.

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9 See CPUC Res. No. 157, issued July 22, 1952 (Ex. 2-15); CPUC Res. No. 216, issued January 16, 1956 (Ex. 2-16); and CPUC Res. No. 387 issued October 22, 1963 (Ex. 2-17).

(Jun. 16, 1975 PG&E Letter (Ex. 2-19).) Among the examples that PG&E collected and submitted to the Commission was one relating to FA-554's treatment of certain GO 112-C records. PG&E wrote in Appendix B to its June 1975 letter:

> <u>PUC GENERAL ORDER 112C</u>
>
> PUC Resolution FA-554 requires a retention period of 40 years for annual reports. All record retention requirements listed in this general order are for the life of the pipeline. Where does the 40 year retention apply?

(Ex. 2-19.) In the wake of this letter, representatives of the Commission and PG&E met to discuss the ambiguities in FA-554. The Commission asked PG&E to draft a proposed new resolution providing retention periods for specific record types of concern to the Commission. PG&E did so, and circulated the proposed resolution to two other utilities (Southern California Edison and San Diego Gas & Electric) for feedback. Both utilities endorsed PG&E's proposed resolution.[10] Subsequently, in August of 1976, the Commission superseded FA-554 with a new Resolution, No. FA-570, which was similar (albeit not identical) to PG&E's proposed resolution. (Ex. 2-21.) FA-570 provided new, comprehensive retention periods for General Order records, including GO 112-C records.

FA-570 marked the first time the Commission addressed comprehensively the retention of records of the kind required to be maintained by General Orders, including the then-applicable GO 112-C. The Commission explained it had made a misstep in 1974 that it now sought to correct:

> By Resolution No. FA-554, this Commission adopted certain retention requirements which supplemented the Federal Power Commission requirements. The Commission has reconsidered the matter of adopting the Federal Power Commission's regulations and based on the Staff's recommendation concludes that Resolution No. FA-554 should be modified and that *<u>preservation of</u>*

[10] Dec. 5, 1975 letter from PG&E to the Commission, and attachments thereto. (Ex. 2-20.)

> *records by gas and electric utilities under the jurisdiction of this Commission should be governed by the regulations of the Federal Power Commission except as modified herein*.
>
> ……….
>
> IT IS ORDERED that the revised regulations for the preservation of records made effective by Federal Power Commission Order No. 450 [*i.e.*, the 1972 amendments to 18 C.F.R. Part 225], except as modified by the specific retention periods for the records contained in this Resolution, are adopted by the Commission for all gas and electric companies operating in this State under its jurisdiction. *Records shall be retained for the periods required by the FPC Order or this Resolution, whichever is the longer period, and may be disposed of after the expiration of such retention periods*.

(Ex. 2-21, at GTR0002273 (emphasis added).)

Within months of FA-570's adoption, in November 1976, PG&E revised its records retention standards for its General Office Departments and Divisions – SP 210.4-3 and SP 210.4-4, respectively – to reflect the Commission's adoption of FA-570. (Ex. 2-22, at GTR0004158; Ex. 2-23, at GTR0004166.) FA-570 may have been the last instance in which the Commission comprehensively addressed records retention, although regulatory activity in this area continues. As recently as October 2007, the National Association of Regulatory Utility Commissioners promulgated model records retention regulations to be used as guidelines by the states in developing regulations to govern the preservation of records of electric, gas and water utilities.[11]

This discussion illustrates several points that the Duller/North Report fails to address. Historic variances may arise between records retention requirements contained in FPC/FERC regulations and the Commission's

[11] National Association of Regulatory Utility Commissioners, *Regulations to Govern the Preservation of Records of Electronic, Gas and Water Utilities* (Rev. Oct. 2007). (Ex. 2-24.)

General Orders, including GO 112-C. It was not until the mid-1970s that the Commission attempted to address those variances. PG&E had a sufficiently vigorous records retention program during this era to undertake a study of the different regulatory requirements and explain to the Commission how those requirements had created inconsistencies and uncertainties. PG&E communicated to the Commission in 1975 its clear understanding that GO 112-C records were generally "life-of-the-facility" records. PG&E quickly refreshed its retention standards in response to regulatory developments (e.g., the adoption of FA-570). The Commission devoted some attention to the subject of records retention in the 1950s, 1960s and 1970s, but does not appear to have considered records retention for utilities since that era.

4. The Corporate Retention Standards Included Audit and Oversight Features.

PG&E agrees that it needs to incorporate better and stronger audit and oversight features into its records retention program. However, that does not mean, as the Duller/North Report suggests, that throughout the past PG&E's retention program lacked audit and oversight features.

To ensure compliance with the 1951 amendments to the FPC regulations, Circular Letter Ex. #642 designated the General Office Department Heads and Division Managers to supervise the preservation, indexing, and destruction of records. (Ex. 2-2.) It required each Division and General Office Department to index its records according to a classification schedule set forth in the letter. And, it required those same Divisions and General Office Departments to send a copy of their index to the office of the "General Auditor" to be maintained as a master index. (Ex. 2-2, at GTR0004110.)

As new generations of standards superseded older ones, audit and oversight features changed. Throughout its life cycle, the SP 210.4-4 series of standards included an audit provision which provided that the Division Records Management Advisor (later Regional Records Management Advisor) should check periodically to see that records were destroyed in accordance with the retention periods set forth in the Records Schedule. (See, e.g., Ex. 2-23, at GTR0004167; Ex. 2-9, at GTR0004213.) Beginning no later than the late 1980s, changes in retention standards suggest increased oversight by the Corporate Secretary and the Law Department. For example, in this era, the Corporate Secretary assumed overall responsibility for issuing, updating, and monitoring compliance with the retention standards. (Corporate Records (Ex. 2-25), at GTR0004228.) Retention standard changes also reflect that the General Counsel assumed a role in providing legal guidance regarding records retention legal requirements. (Ex. 2-25, at GTR0004229.)

The Duller/North Report's further suggestion that PG&E has not audited its records retention program is inaccurate. As early as April 1950, the Company decided to have "traveling auditors" review the condition of records in the Divisions to determine if responsible parties had been complying with the FPC's 1938 records retention regulations.[12]

Moreover, the Commission staff has regularly audited and inspected the gas safety records maintained in PG&E's Divisions. In describing its Natural Gas Safety Program, the Utilities Safety Reliability Branch (USRB) emphasizes its review of a gas utility's operation and maintenance records as part of its gas audit and oversight activities:

> The USRB enforces Federal Pipeline Safety Regulations through its natural gas safety program. The USRB administers its natural gas safety program by auditing the facilities of investor-owned natural gas utilities in California for compliance with the applicable codes. *The audit consists of reviewing operation and maintenance records, evaluating emergency procedures, and performing random field inspections of the natural gas facilities*. Investor-owned utilities are generally audited once every two years; however, the utility may be audited more frequently depending on the results of the audit.

(CPUC Website, Natural Gas Safety Program, http://www.cpuc.ca.gov/PUC/aboutus/Divisions/Consumer+Protection/Utilities+Safety+Branch/Natural+Gas+Safety/index.htm (last visited June 20, 2012) (emphasis added) (Ex. 2-27).) The description of what the Commission staff audits ("reviewing

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12 PG&E letter dated April 4, 1950 to the Chairman of the Coordinating Committee. (Ex. 2-26.)

operational and maintenance records, evaluating emergency procedures and performing random field inspections of the natural gas facilities") captures the staff's historic audit emphasis. Historically, the Commission staff's audits emphasized a review of records maintained at PG&E facilities, usually Division and District offices, that demonstrate that a specified gas safety compliance action, e.g., a leak survey or a line patrol, has occurred. If for the past almost 50 years PG&E's Divisions and Districts have been failing to retain maintenance and operations records of the kind discussed by Dr. Duller and Ms. North, the Commission staff would have brought those failings to PG&E's attention long before now.

As PG&E explained in a data request response, it performed an internal audit of electronic data management practices in 2008. (PG&E's Response to Records OII Data Request 25 Q 8(b) (Ex. 2-28).) The audit identified that although the then-existing records retention and disposal standard (USP 4) defined officer-level accountability for implementing data retention and disposal procedures, the Corporate Secretary lacked sufficient controls to ensure compliance. (Ex. 2-28.) The audit further found that many "business leaders, system owners, and Compliance Champions" do not have any data retention procedures in place, do not monitor compliance with their data retention policies or periodically confirm that the specified retention periods are still valid, and have experienced issues concerning obsolete data in key systems they use. (Ex. 2-28.) The audit recognized that, by April 15, 2009, the Corporate Secretary would establish an action plan to address these issues and that, by September 30, 2009, it would begin an "annual communications campaign" to inform officers of the requirements in USP 4 and begin annual surveys of officers to obtain written confirmations from them regarding compliance with USP 4 as well as to track plans for resolving any shortcomings they identify. (Ex. 2-28.) Consequently, the Corporate Secretary's office began an annual "Compliance Certification" process, whereby every September, the Corporate Secretary's office would send a copy of the operative record retention standard to each line of business. (PG&E's Response to Records OII Data Request 23 Q 35 (Ex. 2-29).) Each line of business would then respond by either acknowledging that it was in compliance, or that it was not in compliance but that it would develop a plan of action for becoming compliant.[13]

In response to the September 2009 compliance certification email from the Corporate Secretary's office, Transmission & Distribution (which at the time consisted of both gas and electric) determined that it should revise its guidance on record retention under USP 4 (the operative standard at the time). The result was the revised "Records Retention and Disposal Guidance for Transmission & Distribution Systems" which became effective in April 2010 (Ex. 2-33).

5. The Corporate Standards Included Process-Centric Elements.

PG&E's records retention standards historically reflected the way the business actually worked. First, the SP 210.4 series of standards reflected the business' organizational structure. SP 210.4-1 addressed accounting records; SP 210.4-2 addressed records of company subsidiaries; SP 210.4-3 addressed records of General Office Departments; and SP 210.4-4 addressed records of Divisions. This separation of standards by function, particularly the separation between SP 210.4-3 and SP 210.4-4, reflected the historic reality of how much of the day-to-day maintenance and operations work of the Company was done regionally in Divisions and Districts.

Second, the standards reflected how records moved through the organization. In the case of PG&E's Departments, records were historically maintained in the Company's General Office until they were no longer frequently consulted. At that point, the Departments had the ability to centrally archive older records at the Bayshore Records Center and recall them for use, as necessary. Dating almost from the time that the Bayshore Records Center was constructed, SP 210.4-3 captured this process. The first revision to SP 210.4-3, effective March 1, 1961, came shortly after the

[13] The CPSD's consultants misunderstand the compliance certification process, asserting that, despite PG&E's statement that Record Retention and Disposal Standard GOV-7001S is to be issued annually in September, the version presented to the Commission in October 2011 was dated October 2010. A new version of the standard is not issued every year; rather, the current standard is re-circulated every year in connection with the compliance process. (Ex. 2-29.) The 2010 version of GOV-7001S is still the current version. (Ex. 2-5.)

newly constructed Bayshore Records Center (see discussion below) had opened in South San Francisco near Martin Station. (Ex. 2-30.) The 1961 revisions included instructions to the Departments for transferring records to the Records Center, procedures for requesting records back once they had been transferred, and provisions ensuring that the Departments would retain the final word before the Records Center disposed of any record.[14]

In contrast, early versions of SP 210.4-4 made no provision for Division records to be archived centrally at the General Office. (Ex. 2-8; Ex. 2-23). This too reflected the operating reality that Divisions historically functioned with a high-degree of autonomy and took responsibility for their own facilities and records, many of which were used infrequently, but when used needed to be readily available locally. Instead, SP 210.4-4 provided that the records would be stored locally, but that the Supervisor of Records would be responsible for providing staff assistance to all Divisions in matters pertaining to records retention, destruction, methods and procedures, housekeeping practices, space layouts, equipment, and other areas of the records management field. (Ex. 2-23, at GTR0004167.) Eventually, SP 210.4-4 provided that information on transferring records to records storage facilities could be obtained by contacting the Supervisor of Records. (Ex. 2-31, at GTR0004244.)

6. PG&E Corporate Records Retention Schedules Addressed Contemporaneous Legal Requirements

CPSD's consultants assert that PG&E misscheduled different kinds of documents in violation of ASME § B31.8; GO 112, 112-A and 112-B; and 49 C.F.R. Part 192.709. In several instances their allegations merely highlight the difficulty in trying to find fault with policies and schedules issued and maintained so long ago.

Dr. Duller and Ms. North are critical of the retention periods for "Line Patrol Reports" listed in PG&E's 1994, 2005, and 2008 retention schedules. Yet each of those schedules provide that line patrol reports shall be retained for *<u>the life of the facility for numbered gas transmission lines</u>* and three years

[14] The Office of Corporate Secretary would later, in 1962, assume responsibility for administering the Records Center.

for all other lines. (Ex. 2-11, at GTR0004316; Ex. 2-12, at GTR0004420; Ex. 2-13, at GTR0004479.) The CPSD acknowledged its mistake in discovery responses served after the Duller/North Report was issued: "CPSD notes that a violation would exist with the requirement to keep any non-numbered Gas Transmission Line for only three years. CPSD would make this addition as errata to Appendix 9 of Dr. Duller's and Ms. North's report and Appendix 8 of Ms. Felts' report. (This requirement is to also keep numbered gas transmission lines for the life of the facility.)" (CPSD's Response to Records OII Data Request 8-Q4 (Ex. 2-32).)

Dr. Duller and Ms. North are also critical of PG&E's 1994, 2005, and 2008 retention schedules for requiring that "Line Inspection Reports" be retained for only three years, in violation of the ASME standards and 49 C.F.R. Part 192. It would seem, however, that PG&E's mistake (if attempting to take account of a federal regulation in a retention schedule can be considered a mistake) was to schedule a category of records described in the FERC records retention regulations. The 1994, 2005, and 2008 retention schedules addressing "Line Inspection Reports" each reference "FERC 23D." That is a reference to Part 225.3, Subsection (d) ("Records of general inspection and operating tests") of Section 23 ("Transmission and distribution—Gas"). It too specifies a three-year retention period. (Ex. 2-11, at GTR0004316; Ex. 2-12, at GTR0004420; Ex. 2-13, at GTR0004479.)

Dr. Duller and Ms. North also criticize PG&E's 2010 schedule for mandating retention of "Leak Survey Maps" for only nine years, when Part 192.709(c) has required since 1996 that such records be kept for five years or until the next leak survey, whichever is greater. (Ex. 2-33, at GTR0002478.) Even assuming that "Leak Survey Maps" qualify as a record of a "patrol, survey, inspection, and test" under Part 192.709(c), Dr. Duller and Ms. North have to stack several layers of assumptions on top of one another to conclude that a nine-year retention period is insufficient to meet a five-year (or until the next leak survey) retention period. PG&E performs leak surveys of its transmission lines annually for Class 1 and 2 lines and semi-annually for Class 3 and 4 lines. (UO Standard S4110: Leak Survey and Repair of Gas Transmission and Distribution Facilities – Attachment 1

(Ex. 2-34), at GTR0118239.) And, the Commission historically has regularly performed audits of Division and District leak records, including audits of two Districts per year.

In any event, PG&E's retention schedules from 1994, 2005, 2008, and 2010, all include entries for "Leak Survey Inspections" and/or "Leak Survey Logs" with mandated retention periods of life of the facility or in some cases longer. (Ex. 2-11, at GTR0004316; Ex. 2-12, at GTR0004420; Ex. 2-13, at GTR0004479; and Ex. 2-33, at GTR0002478.) With respect to those records, the retention schedules complied with – and after 1996 exceeded – Part 192.709(c), which provides that a record of each patrol, survey, inspection, and test must be retained for the life of the facility (from 1970 to 1996) or for at least five years or until the next survey or inspection (but not map) is completed, whichever is longer (from 1996 to the present).

The Duller/North Report attempts to read PG&E's historic records retention schedules in a vacuum and without any reference to context. There is no acknowledgement in the report that the CPSD was regularly auditing gas pipeline safety records maintained in PG&E's Divisions and Districts during the period of the alleged violations. Nor is there any acknowledgement that the Commission's records retention resolutions were, at least prior to 1976, focused on the FPC regulations. In 1964, the Commission had itself just recently adopted the FPC's Part 225 retention schedules through CPUC Resolution No. 387 issued on October 22, 1963 (Ex. 2-17), but did so without referencing General Order 112 or any other General Order. As discussed, the Commission did not undertake the effort of harmonizing the FPC's records regulations and the Commission's General Order retention provisions until the mid-1970s.

The above examples illustrate why PG&E's historic records retention schedules need to be read contextually and with the then-applicable retention requirements in mind. One of the hazards of alleging a records retention schedule violation over a span of more than 55 years is that it is difficult to resolve ambiguities by reference only to the decades-old retention schedules. The task becomes even more difficult when little account is taken of the FPC and FERC regulations, and when no reference is made to an environment in which those records were audited year after year.

a. Records Transmittal, Storage and Destruction

Reading PG&E's retention schedules in isolation, CPSD's consultants formed the view that PG&E historically treated the subject of records retention largely as a cost-saving exercise.[15] Again, their analysis lacks historical context.

In 1958, PG&E's management approved the construction of the original Bayshore Records Center; construction began in 1959 and was completed in 1961. (Pacific Gas and Electric Company Records Center History (Ex. 2-35).) As we have seen, beginning in 1961, SP 210.4-3 was revised to create a procedure for General Office Departments to transfer older records to the Records Center. (Ex. 2-30, at GTR0004117.) Records previously stored at other off-site locations were also consolidated at the Records Center. Records previously stored at 530 Bush Street were transferred to the Records Center in 1965. (Ex. 2-35.) Plant accounting records stored in Sacramento were transferred there in 1967. (Ex. 2-35.) Records from 345 Mission Street were transferred there in 1970. (Ex. 2-35.)

Within a few years of when it opened, the Records Center struggled to make room for the growing volume of paper records. The original Bayshore Records Center reached capacity in 1967. (Ex. 2-35.) A 1967 expansion of the Records Center doubled its capacity, but by 1971, the expanded Bayshore facility had again reached capacity. (Ex. 2-35.) The Company used an additional facility (known as the Sugar House) at the Potrero Power Plant for records storage and later in the mid-1970s began using the 33rd floor at the Company's headquarters to store records. (Ex. 2-35.) Despite these efforts the records storage problem grew. The Company undertook at least two studies in this era to determine solutions, including the feasibility of microfilming increasing numbers of records.[16] (Evaluation of Feasibility: Microfilming Vital Records Housed in the Records Center (Ex. 2-36).) In 1983, the

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[15] Duller/North Report at 6-33.

[16] A study of the records storage problem done in the mid-1970s indicated that in 1974 the Records Center took in 6,589 cubic feet of new records but only disposed of 2,965 feet. (Ex. 2-36.)

Company completed a further expansion of the existing Records Center, known as the Western Addition of the Records Center, to accommodate the growth in the volume of records being archived.[17] (Ex. 2-35.) At about this same time, PG&E developed a computer system that allowed for the tracking of records when they entered, left or were transferred among PG&E storage facilities. (P2-1469.) The system also allowed for the Records Center to generate periodic reports, a task that formerly took numerous hours to complete. That system was transferred to a PC desk top system in 1985. (Ex. 2-35.)

Today, the Bayshore Records Center still functions as a repository, but in a more limited sense. In 2011, as part of the initial phase of the MAOP Validation project, numerous records, including gas transmission records, were transferred out of the facility. PG&E's Emeryville facility now serves as a central repository for many (but not all) gas transmission pipeline construction and testing records.

b. The Retention of Pipeline History Files

In her supplemental report, Ms. Felts asserts that PG&E's inability to locate "Pipeline History Files" violates Public Utilities Code Section 451, ASME § B31.8, and PG&E's internal guidance requiring retention of engineering records. She refers to Sections 4.1.1 and 4.1.2 of the Felts Report for supporting analysis and contends that the violations arose in 1987 and continued through 2010. The Duller/North Report also criticizes PG&E for not retaining Pipeline History Files, suggesting that the failure to account for the files today is evidence of the "subjective" way in which PG&E implemented its retention standards.[18]

The Pipeline History Files that the CPSD's consultants describe would have been created pursuant to former Standard Practice 463.7. (PG&E's Response to Records OII Data Request 34 Q 1 (Ex. 2-37).) SP 463.7 addressed the subject: "Pipeline History Files, Establishing and Maintaining." (Ex. 2-38.) The standard was meant to provide "a

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17 So great were the records storage problems during this era, that the Company entertained the idea of lobbying to change the regulations for storage mandated by FERC and the Commission.

18 Duller/North Report at 6-37 and 6-47.

current and uniform history record of pipelines (and mains) that have a Maximum Allowable Operating Pressure (MAOP) resulting in a hoop stress equal to or greater than 20% of the Specified Minimum Yield Strength (SMYS)." (Ex. 2-38.)

In its original iteration, SP 463.7 gave responsibility for establishing and maintaining Pipeline History Files to supervisors out in Division offices and to the Pipeline Operations Department, a predecessor organizational structure to PG&E's current gas transmission Districts. The Supplement to SP 463.7 described the data that the history file should include. (Ex. 2-38.)

Available versions of SP 463.7 suggest that the standard imposed two reporting requirements on each responsible Division or Department. The first required the Division or Department to submit to the Manager of Gas System Design a completed initial copy of the 8-letter size form entitled "Pipeline Survey" and to annually submit updated "Pipeline Survey" Sheets. (Ex. 2-38.) It imposed the further obligation on Divisions to submit annually, before February 1, to the Manager of Gas Distribution, a completed copy of Form 75-352 "Annual Report for Pipeline and Mains Operating At or Over 20% SMYS" for each pipeline and main covered by the standard. The form (Exhibit A to SP 463.7) is identified as a GO 112-B form, indicating that it was an annual report then required under GO 112-B.[19] (Ex. 2-38.) As for recordkeeping, SP 463.7 required that "[h]istory records for numbered transmission lines shall be filed by line number, with all pertinent inclusions of data shown in paragraphs 5 and 6, indexed for ready reference, and cross-

[19] General Order 112-B imposed annual reporting requirements relating to the surveillance of pipelines and mains and the operation and maintenance studies for pipelines operating above 20% SMYS. (GO 112-B, sections 401.5 and 401.6 (eff. 1967).) SP 463.7 suggests that PG&E compiled the Form 75-352's submitted by the Divisions and Pipeline Operations Department and submitted them to the Commission as part of its annual report. (Pacific Gas and Electric Company Pipeline Surveillance Procedures, Operating and Maintenance Studies, and Location Class Changes (Mar. 1969).) The Commission's reporting requirements relating to the surveillance of pipelines and mains (Section 401.5) were short-lived. They were removed in 1971 when the Commission adopted GO 112-C. The requirement to file reports summarizing operating and maintenance studies (Section 401.6; later Section 141.4) lasted longer. It was retained through GO 112-D, before being removed with the adoption of GO 112-E (eff. 1995).

referenced to other permanent files, such as GM or Work Order files." (Ex. 2-38.)

Former SP 463.7 appears to have taken effect in 1969 and been operative until no later than October 1987. A letter dated October 9, 1987 from the Organization Planning and Development Department to Officers and General Office Department Heads lists SP 463.7 among several Standard Practices that "[w]e have been asked to cancel." (Ex. 2-39.) A May 3, 1984 memo from the San Joaquin Gas Superintendent to San Joaquin Division District Managers suggests that SP 463.7 remained in effect as of at least that date. (Ex. 2-40.)

In the words of Dr. Duller and Ms. North, the Pipeline History Files were "really a secondary source of information," and in this regard they appear to be right.[20] The "Pipeline Survey Sheets" – a main output of the SP 463.7 standard – contained a summary of data about the pipeline reduced to a single sheet of paper. SP 463.7 also required the Divisions to keep in the Pipeline History Files selected documents relating to the numbered transmission lines, but these documents were themselves copies of underlying documents, as SP 463.7 makes clear. (Ex. 2-38.) SP 463.7 speaks in terms of those document files as being cross-referenced to "other permanent files, such as GM or Work Order Files." (Ex. 2-38.) This is a reference to job files of the kind that PG&E uses today as part of the MAOP records verification and MAOP validation effort.

It is true, as Ms. Felts says, that SP 463.7 required that the Pipeline History Files be maintained for the "life of the facility," but that requirement arose by operation of SP 463.7, not by operation of law. When SP 463.7 was rescinded no later than October 1987, its "life of the facility" requirement was rescinded along with it. Once SP 463.7 was rescinded, the Divisions, Departments, and Manager of Gas System Design would have been holding onto secondary sources of information and copies of original documents found elsewhere, such as in job files.

[20] In discovery, the CPSD similarly acknowledged that the Pipeline History Files were "derived from a variety of primary sources such as the job folders[.]" (CPSD's Response to Records OII Data Request 8 Q 1.)

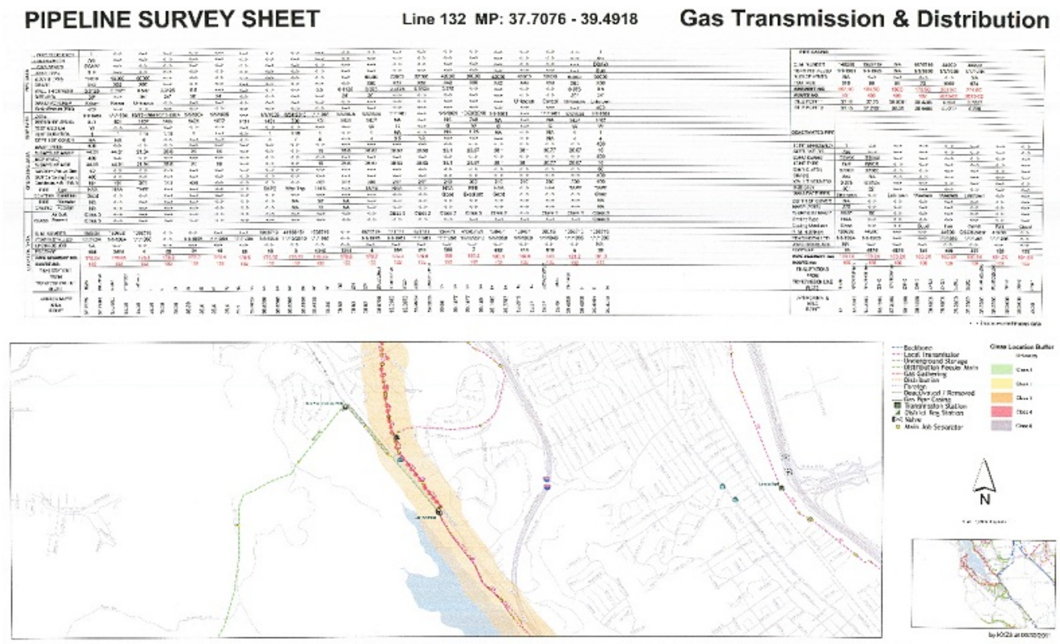
At that point, SP 463.7 documents would have been subject to disposal under the Company's records retention standards.[21]

The Pipeline Survey Sheets – a key output of SP 463.7 – were retained even after SP 463.7 was rescinded. An example of a Pipeline Survey Sheet appears below. It contains a plan view scale map showing the location of the pipeline, accompanied by tabular information such as the following:

- pipe data (joint efficiency, girth welds, long seams, joint type, SMYS, grade, wall thickness, size – OD, manufacture, design pressure);
- test data (data, pressure, test medium, test duration, depth of cover);
- operating data (MAOP, percent SMYS at MAOP, MOP, percent SMYS at MOP, pipe coating type and condition);
- pipe casing diameter and footage; and
- location data (class as built and present, GM number, year installed, footage, pipe segment number, route number, stationing from transmission line plats, approximate point).

[21] For example, SP 210.4-3 (eff. 4/1/94) addresses duplicate records in the following terms: "Duplicate copies of records should be destroyed as soon as they have served their intended purpose and proper retention of the original document has been verified." (Ex. 2-10, at GTR0004265.)

FIGURE 2A-1
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SURVEY SHEET



The Pipeline Survey Sheets would later be used in the 1990s to populate the initial gas transmission GIS.

In retrospect, the Company wishes it had retained the Pipeline History Files. Those files would have likely enhanced the Company's ability to respond to the NTSB's January 3, 2011 recommendations and the Commission's directives to aggressively and diligently search for design basis records needed to confirm MAOP. But in asserting that PG&E violated the law by not retaining copies of records maintained under a now-abolished standard, the CPSD's consultants confuse the desirable with the mandatory.

c. The Retention of Patrol, Survey, Inspection, and Test Records

Many of the Duller/North records retention violations share a common thread: they assert that PG&E's corporate records retention standards and schedules did not prescribe sufficient retention periods for the kinds of line patrol, survey, inspection and test records formerly required to be maintained by GO 112 (incorporating ASA §§ B31.8 and 851.5) and 49 C.F.R. 192.709.[22]

[22] Duller/North Supplement at Section II.B.1–II.B.5.

Missing from the Duller/North analysis, however, is any substantive discussion of the utility standards that actually govern how PG&E's gas organization retained records in connection with these activities. In its June 20, 2011 filing, PG&E provided an attachment that detailed records-related utility standards, work procedures and bulletins. Included in that attachment were standard practices, bulletins, and forms governing activities of the kind covered by Section 851.5 and Part 192.709. (See, e.g., SP 460.2-1 (Patrolling Pipelines and Mains) (P2-1240); SP 460.21-4 (Routine Inspection for Gas Leakage) (P2-1149); SP 460.2-2 (Physical Inspection: Pipelines, Mains, and Services) (P2-1325).) Those standard practices, bulletins, and forms included provisions governing the creation and retention of records. (See generally P2-1149 to P2-1244.) It was these "Gas Standards" – more so than corporate retention schedules – that drove the records decisions about pipeline records made by personnel in PG&E's gas organization.

As Maura Dunn explains in greater detail in her Expert Report, the omission is significant. Included within PG&E's standard practices were requirements that respond to many of the Duller/North Report's specific allegations.

CHAPTER 2B

PG&E'S RECORDS RETENTION POLICIES MET APPLICABLE REGULATORY RECORDKEEPING REQUIREMENTS

Maura Dunn, a records management expert, responds to assertions contained in the Duller/North Report about PG&E's records retention policies that form the basis for the alleged violations that appear in Section II.B of the Duller/North Supplement. Her response is contained in the Expert Report of Maura L. Dunn, MLS, CRM PMP, which is incorporated here by reference.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

PG&E'S USE OF RECORDS

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CHAPTER 3
PG&E'S USE OF RECORDS

This chapter addresses PG&E's use of gas transmission pipeline records. It primarily responds to Ms. Felts' allegations that records are missing, incomplete or inaccessible, and that these shortcomings impacted PG&E's gas pipeline safety efforts, and particularly its Integrity Management Program.[1] This chapter addresses the following violations asserted in the Felts Supplement:

16. Job Files Missing and Disorganized
18. Design and Pressure Test Records Missing
19. Weld Maps and Weld Inspection Reports Missing or Incomplete
20. Operating Pressure Records Missing, Incomplete or Inaccessible
21. Pre-1970 Leak Records Missing, Incomplete or Inaccessible
22. Post-1970 Leak Records Missing, Incomplete or Inaccessible
23. Records to Track Salvaged and Reused Pipe Missing
26. 1988 Weld Failure – No Report
27. The 1963 Weld Failure – No Report

This chapter also addresses the three violations alleged in Part II.C of the Duller/North Report. Those violations relate to PG&E's Gas Pipeline Replacement Program (C.1), the maintenance of records that relate to risks associated with earthquakes (C.2), and the collection of data relating to historic gas pipeline leaks (C.3).

This chapter has seven parts. In Part A, John S. Zurcher addresses how pipeline records have been used in the gas pipeline industry, particularly with the advent of risk assessment and integrity management processes.

Part B provides a brief historical overview of the development of PG&E's gas transmission system. This overview initially appeared in Chapter 1A of PG&E's June 20, 2011 submission.

Part C addresses PG&E's historic use of engineering, construction, operations, and maintenance records, including allegations about PG&E's use and tracking of reconditioned pipe, its numbering and indexing of job files, and its handling of material failure reports.

[1] Felts Report at 26-47.

Part D addresses two related topics: records relating to PG&E’s ground movement program, and PG&E’s decades old Gas Pipeline Replacement Program.

Part E addresses specific allegations contained in the Felts Report about PG&E’s Integrity Management program.

Part F specifically addresses how leak records have historically been maintained and used.

Part G responds to allegations in the Felts Report concerning PG&E’s GIS.

CHAPTER 3A
EXPERT TESTIMONY OF JOHN ZURCHER REGARDING HISTORICAL RECORDKEEPING PRACTICES IN THE NATURAL GAS PIPELINE INDUSTRY

1. QUALIFICATIONS AND MATERIALS REVIEWED

a. Qualifications

I am a gas pipeline consultant with extensive experience in pipeline design, construction, operations, maintenance, integrity management and pipeline safety. I am a managing director and co-founder of the Blacksmith Group (Blacksmith), and a principal of Process Performance Improvement Consultants, a Blacksmith subsidiary. Through both of these positions, I provide consulting services to pipeline operators in areas including risk management and regulatory compliance. I also provide consulting services to industry trade associations and research organizations, particularly in the areas of industry standards, pipeline safety regulations, and best practices in risk and integrity management. I also work with pipeline operators to audit their regulatory compliance plans, help them interpret pipeline safety and integrity federal regulations, and tailor their programs to meet these standards. In my consulting practice, I have conferred extensively with pipeline operators concerning their practices, both currently and historically.

My professional experience in the gas pipeline industry spans thirty-five years. I have been extensively involved in pipeline design and safety. Prior to co-founding Blacksmith, I served as the Vice President of the Hartford Steam Boiler Inspection and Insurance Company's (HSB) Pipeline Group. At HSB, I counseled pipeline operators in areas such as pipeline integrity management, risk management, and emergency response protocols. I was also consulted for my expertise in the areas of pipeline operations, safety regulations, and maintenance processes. Before joining HSB, I was the Manager of Pipeline Safety at Columbia Gas Transmission. In this role, I oversaw the company's regulatory compliance, risk management, and emergency response programs. Among other positions, I have also served as Tenneco Energy's Director of Pipeline Services, where I was responsible for pipeline integrity and safety projects. I also served as Manager of Engineering at Panhandle Eastern Corporation, where I focused on compliance with regulatory and consensus standards, led design and development of the company's first geographic information system (GIS) database, and was responsible for the company's engineering records systems relating to operations, maintenance, and construction. At Panhandle Eastern, I was also responsible for quality assurance (QA) for the company's design and construction programs. In addition, I was the Manager of Engineering at Colorado Interstate Gas Company, where I ensured that all facilities were built and maintained in accordance with government regulations and consensus codes and standards.

I have actively participated in industry-related professional organizations for most of my career. I was Chairman of the Gas Piping Technology Committee's Transmission Division, and Chairman of the Gas Technology Institute's Integrity Maintenance and Systems Operations Group for eight years, respectively. I served as Chairman of the Interstate Natural Gas Association of America (INGAA) Pipeline Safety Committee for nearly a decade. I have also served on an INGAA Task Force charged with developing methods to systematically improve pipeline integrity management practices, and co-led the drafting of the Integrity Management Standard for natural Gas Transmission Pipelines, published by the American Society of Mechanical Engineers (ASME) in 2002.

I have been extensively involved in the creation of pipeline-related rules and standards throughout my professional career. For the past 30 years, I have been a member of ASME's B31.8 Section Committee; this Committee revises and issues interpretations of ASME B31.8 – an industry standard covering the design, fabrication, inspection, testing, and other safety aspects of the operation and maintenance of gas transmission and distribution systems. I was one of the lead authors of the original B31.8S, published in 2002, and I have continued to update it over time. In connection with my work on behalf of the Gas Technology Institute, I directed interviews of those responsible for drafting the 1955 edition of B31.8 (then-titled B31.1.8-1955) code provisions as well. As a member of the B31.8 Committee, I have also become very familiar with the practices of many companies operating gas pipelines.

I am a member of the National Association of Corrosion Engineers (NACE), and have served on a number of committees within that organization. I have assisted NACE, the American Society for Nondestructive Testing, and the American Petroleum Institute in coordinating their standards with those created by the ASME. Moreover, I have worked with INGAA to help ensure that rules drafted by the Federal Office of Pipeline Safety reflect the practical realities of pipeline operations.

In 1995, I was appointed by the Secretary of Transportation to the Department of Transportation (DOT) Technical Pipeline Safety Standards Committee – an appointment I held for two terms. I have been called to testify on behalf of the gas industry before the United States Congress on matters related to pipeline safety. Furthermore, I was a member of the DOT Risk Management Quality Action Team, and the DOT Mapping Quality Action Team.

I earned a Bachelor of Science in Electrical Engineering from the University of Colorado in 1977, and a Master of Science in Business Administration from the University of Northern Colorado in 1981. My curriculum vitae is included as Appendix A to this Chapter.

b. Materials Reviewed

My analysis and conclusions are based on, among other things, a review and analysis of data and records concerning the physical assets and operations of PG&E's gas transmission Line 132; materials relating to PG&E's Integrity Management program; sworn interviews and testimony regarding the San Bruno accident and the operation of PG&E's Integrity Management program, including from third-parties; the National Transportation Safety Board report on the accident; testimony prepared by the CPUC's Consumer Protection and Safety Division (CPSD); testimony prepared by John Gawronski on behalf of the City and County of San Francisco; the report and testimony of Margaret Felts on behalf of the CPSD; and a visual examination of segments of gas transmission Line 132, including portions of Segment 180.

My analysis and conclusions are also based on third-party publications and studies regarding the gas pipeline industry and data reported to third-parties by gas pipeline operators, including, but not limited to, incident data reported to the DOT and valve data reported to INGAA. In addition, my analysis and conclusions are based upon my discussions with gas pipeline operators concerning their practices over the years in operating and testing their pipelines.

2. ANALYSIS AND CONCLUSIONS

a. Missing or Incomplete Records for Pipelines Installed Prior to 1970 are Common in the Gas Pipeline Industry

The federal pipeline safety regulations set forth in 49 CFR Part 192 (Part 192) became effective in November of 1970. Nearly two-thirds of onshore natural gas transmission pipelines in service today were installed prior to this date. These pipelines were generally installed and had their maximum allowable operating pressure (MAOP) established under the ASA B31.1 standard (for pipelines installed from 1933-1951), the ASME B31.8[2] standard (for pipelines installed in and after 1952), or the internal standards maintained by individual operators.

(1) Impact of the Grandfather Clause on Operator Recordkeeping Practices and Record Utilization

Based on my experience in the industry, I believe that after Part 192 took effect, many operators generally established the MAOP for some portion of their natural gas pipelines installed prior to 1970 through the method articulated in Section 192.619(c) (the grandfather clause). The grandfather clause provided that “notwithstanding” the provisions of 192.619(a) and (b) (which, briefly summarized, provided that pipelines must be operated at an MAOP derived from the lowest of three specific measures), operators were permitted to rely upon records establishing the highest operating pressure to which the pipeline was subjected

[2] Originally titled ASA B31.1.8-1952.

between 1965 and 1970 to establish the MAOP. After this point, operators may have consulted records relating to their grandfathered pipes (such as strength tests or design specifications) for purposes of maintenance, establishing class location or performing integrity management assessments. However, after establishing a pipe's MAOP under the grandfather clause operators did not generally revisit these historical records in connection with the MAOP for those pipes.

PHMSA has recognized the historical impact of the grandfather clause on industry recordkeeping practices. In a May 7, 2012 advisory bulletin regarding operators' verification of records, PHMSA indicated that "[t]he third method, often referred to as the 'grandfather clause,' allows pipelines that had safely operated prior to the pipeline safety MAOP regulations to continue to operate under similar conditions *without retroactively applying recordkeeping requirements* or requiring pressure tests" (emphasis added). (PHMSA Advisory Bulletin, 77 Fed. Reg. 26822, 26823 (May 17, 2012) (Ex. 3-1).) PG&E's well-publicized and wide-ranging efforts to locate strength test pressure and material records for its formerly grandfathered pipes should be evaluated against the historical de-emphasis of such records for purposes of establishing MAOP.

(2) Historical Recordkeeping in the Natural Gas Industry

Among other requirements, the new regulations introduced in Part 192 in 1970 mandated that operators maintain certain records relating to the design, construction, operation, and maintenance of transmission pipeline systems, including records sufficient to establish the MAOP for a given transmission pipeline. However, common sense and historical perspective suggest that the quality of records maintained by pipeline operators will vary with the age of the pipe in question. Over the years, many operators misplaced or discarded various underlying source materials reflecting pipeline characteristics or operating history after using such materials to establish a pipeline's MAOP. Many operators have also been party to reorganizations, changes in ownership structure and the acquisition and divestiture of various assets, further complicating efforts to maintain complete and accurate historical records. In my experience, it is very common for pipeline operators to have missing or incomplete records for various pipelines or pipe segments in their respective systems, particularly for pipelines installed prior to 1970.

b. Prior to 2004, Pipeline Records Were Not Generally Utilized to Ensure the Structural Integrity of Natural Gas Pipelines

Prior to the 2004 effective date of the 2002 Pipeline Safety Improvement Act and subsequent regulations, which I discuss in greater detail below, the industry viewed the primary purpose of pipeline records retained by operators as a way to document and verify compliance with regulations and the completion of certain safety-related actions such as the design and construction of pipe according to certain specifications, the completion of routine pipeline patrols, the conduct of leak surveys or the repair of any detected leaks within a specified timeframe. Operators were *not* generally required to utilize such records for the purpose of determining the condition of their pipelines or of specific pipe segments. While a limited number of operators had started to experiment with records-based "risk management" practices prior to the era in which the integrity management principles discussed below were adopted, operators did not generally utilize pipeline records for purposes of ensuring the systematic, comprehensive and integrative structural integrity of their pipelines.

c. The Development of Integrity Management Programs Enhanced Operators' Integration and Utilization of Pipeline Data

In the wake of the Bellingham and Carlsbad pipeline accidents of 1999 and 2000, respectively, government regulators and the gas pipeline industry worked together to develop a system to manage structural threats that might impact the safe operation of gas transmission pipelines. Arguably the most significant pipeline safety legislation in decades, Congress enacted the Pipeline Safety Improvement Act of 2002, in which specific regulations relating to integrity management (Integrity Management) programs were born. The Integrity Management rules did not materially alter the nature of historical pipeline data that operators were required to maintain. Rather, the rules provided operators with a structure for integrating this historical pipeline data into a comprehensive assessment of the integrity of pipelines in service and provided guidance regarding the creation and maintenance of certain records specific to the Integrity Management process.

(1) The Integrity Management Regulations Recognized the Inherent Limitations of Pipeline Records and Introduced the Assessment Method for Evaluating Risk in Light of these Limitations

The Integrity Management rules developed in the early 2000s were in part motivated by the evolving understanding among industry participants and government regulators that historical records, while informative, did not always provide enough information relating to the current state of many pipelines in operation, and that the then-current operations and maintenance requirements could not always ensure the safe operation of pipelines. The Integrity Management rules were drafted with the expectation that existing pipeline records would provide information sufficient to make reasonable, conservative assumptions about the present condition of pipe in operation, but that additional measures were required to account for a variety of threats. For example, pipe located in highly-corrosive soil that has experienced periods of inadequate cathodic protection would suggest to an operator that the pipe might have sustained corrosion, but could not state the volume of metal loss on the pipe at issue or the extent of corrosion on other similar segments. The Integrity Management rules thus required operators to conduct integrity assessments of their pipelines in order to validate existing assumptions and/or provide information that would either change or confirm the assumptions and, potentially, lead to additional assessment, examination, evaluation, and remediation. These ongoing Integrity Management assessments were intended in part to address known and anticipated gaps in operators' knowledge about their pipeline systems.

(2) The Integrity Management Regulations Took into Account the Well-Recognized Nature of Incomplete Pipeline Records Throughout the Gas Industry

Through incorporation of ASME B31.8S (titled Managing System Integrity of Gas Pipelines) into Part 192, the federal rulemaking process recognized and sought to account for the well-known limitations of record-keeping throughout the industry. While ASME B31.8S provides that "[c]omprehensive pipeline and facility knowledge is an essential component of a performance-based integrity management program," it also allows an operator to use the prescriptive process where the operator lacks sufficient data. (ASME B31.8S § 4.1.) This is reflected more strongly in the case of operators such as PG&E implementing prescriptive Integrity Management programs, who are to gather the "[l]imited data sets" articulated in Appendix A. (§ 4.2.1.) For example, for a manufacturing threat assessment, this data includes (a) pipe material, (b) year of installation, (c) manufacturing process, (d) seam type, (e) joint factor, and (f) operating pressure history. (§ 4.2.) For both the prescriptive and performance-based programs, ASME B31.8S contemplated that the assessment process would augment existing records by providing information from inspection, examination, and evaluation data. (§ 4.3.)

ASME B31.8S specifically recognizes that operators may not possess complete historical records, and articulates steps permitting operators to substitute conservative assumed values where pre-existing documentation is lacking. In the case of manufacturing threats, operators are further permitted to reference sources such as the *History of Line Pipe Manufacturing in North America* to fill in missing pipe specifications. (§ A4.2.)

d. Ms. Felts' Critiques of PG&E's Recordkeeping and Regulatory Compliance are Inaccurate and Unfounded

I have reviewed and analyzed the report of Margaret Felts submitted in this proceeding. Ms. Felts offers a critique of PG&E for its alleged failure to maintain records relating to pipeline operating pressure history, x-ray records, and weld maps. Based upon my professional experience in the industry and knowledge of pipeline safety and integrity management regulations, I disagree with Ms. Felts' conclusions.

As a preliminary matter, Ms. Felts does not identify any recordkeeping requirements in the Integrity Management rules or within ASME B31.8S that require an operator to maintain historical records of the sort listed above, nor am I personally aware of any such requirements based on my extensive experience in the industry. For example, operators are not required to maintain records of over-pressure events on transmission lines unless such events exceeded 110% of MAOP or 75% of SMYS. The Integrity Management rules do require retention of pressure history records for the specific types of pipe enumerated in 49 C.F.R. §§ 192.917(e)(3) and (e)(4). For those pipeline segments identified as subject to manufacturing threats specific to the pipe seam and operating in a high consequence area (HCA), the rules require that an operator limit the maximum pressure to no greater than the highest operating pressure in the five years prior to identification of the HCA, or, in the alternative, to conduct a hydro test of the pipe in question.

The rules requiring operators to implement Integrity Management programs mandated compliance by December 17, 2004, meaning that PG&E was required to limit operating pressure on pipes operating in HCAs to no greater than the highest pressure experienced since 1999. Missing or incomplete operating pressure data for 1999 would not have a discernable negative impact on PG&E's determination and assessment of a manufacturing threat under this rule. If a pipeline reached its highest historical operating pressure in 1999, and PG&E lacks documentation of such an event, the consequence is that PG&E has subsequently operated the pipeline at a maximum pressure *lower* than that to which the pipe has previously been subjected. If a pipeline operated throughout 1999 at a pressure *below* its highest historical operating pressure, then data to that effect would not inform PG&E's establishment of the highest operating pressure for that pipe.

Ms. Felts' claims regarding the consequence of missing or incomplete records of x-ray film, girth weld inspection reports and weld maps are similarly inaccurate. Federal regulations do not currently require, and have not historically required, operators to subject all girth welds on their system to x-ray inspection, nor am I aware of any requirement that operators maintain film of those girth weld x-rays that they do conduct. For Integrity Management purposes, operators utilize information or conservative assumptions regarding the vintage and method of welding employed on their pipelines, given that particular construction methods such as acetylene girth welding have proven susceptible to ground movement regardless of the size or quantity of imperfections in the girth weld. Operators often derive such knowledge or conservative assumptions regarding the welding method employed from records relating to construction of the pipeline in question.

I have also reviewed and considered Ms. Felts' statements regarding PG&E's use of reconditioned pipe in its system. Again, I disagree with Ms. Felts' conclusions. The use of reconditioned pipe without specific inspection practices was common within the gas industry into the late 1960s. Ms. Felts accurately states that since the 1970 enactment of part 192.13, reusing pipe has been an acceptable practice when the salvaged pipe is subjected to the requisite inspection and testing to affirm its structural integrity prior to reinstallation. Absent evidence of structural damage revealed during the inspection, or known concerns regarding potential manufacturing defects (such as particular historical vintages of A.O. Smith pipe identified in the 1980s as subject to potential defects), pipe can reasonably be reconditioned and reinstalled regardless of its age. While Ms. Felts asserts that it would be "prudent" for operators to track the age of reconditioned pipe in their systems, Ms. Felts does not cite any historical regulation requiring such a practice, nor am I aware of any such regulation for pipe installed prior to 1970.

CHAPTER 3B

PG&E'S GAS TRANSMISSION SYSTEM

This section, which was filed as Chapter 1A of PG&E's June 20, 2011 filing, provides an overview of PG&E's transmission system, including its historical development.

Natural gas has been distributed by pipeline in some areas of the country for over a hundred years. (GTH-48.)[3] Pipeline systems expanded to meet demand during strong economic cycles and in response to population changes. More than sixty percent of the Nation's gas transmission pipelines were installed before federal regulations took effect in 1970. (GTH-61.) Some gas transmission and distribution utilities, such as PG&E, which began as small operations, grew through mergers or acquisitions to service a larger territory. Their systems changed character as interstate transportation of natural gas became more prevalent following World War II. The transmission systems of these companies tend to be heterogeneous, meaning that their pipeline systems are of different age, materials, diameter, pressure, and specifications.

The term heterogeneous aptly characterizes PG&E's transmission system. PG&E's service territory is large; and its pipeline construction, maintenance and operations activities stretched across a large part of California. A significant portion of PG&E's existing transmission system was installed before extensive pipeline safety regulation, before pipeline recordkeeping regulations, and before technological changes that have improved modern data management and retrieval processes. The existing pipeline system is diverse in terms of its specifications and its age. For these reasons, it is difficult to generalize about the system's design and construction or PG&E's historic maintenance and operations practices.

1. An Overview of PG&E's Existing Transmission System

PG&E serves 15 million natural gas and electric customers (4.3 million individual gas accounts) in northern and central California. Its service territory covers 70,000 square miles.

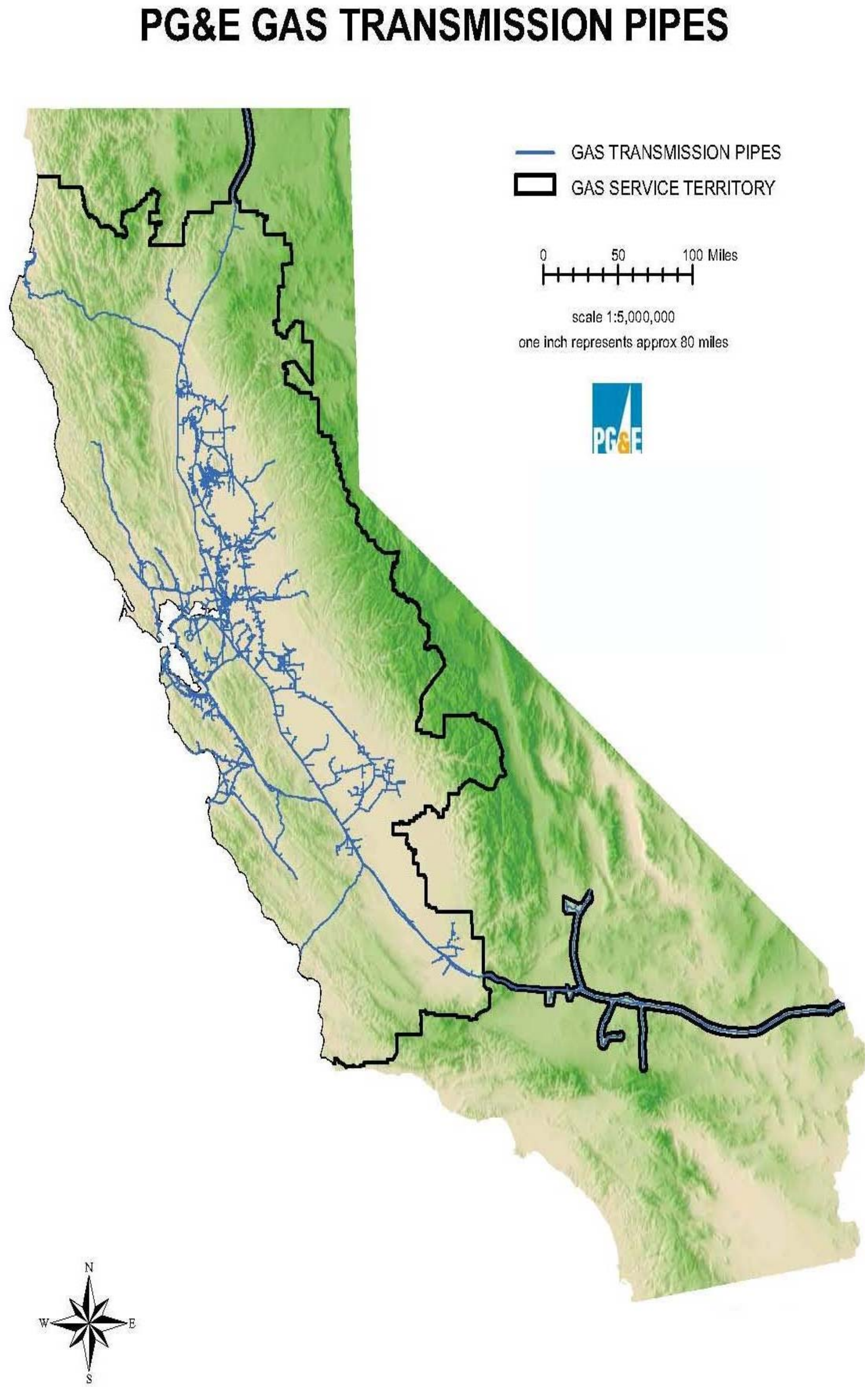
The system comprises approximately 6,750 miles of pipeline operating at pressures greater than 60 pounds per square inch gauge (psig), approximately 40 miles of gas gathering pipeline, and more than 42,000

[3] All references to attachments can be found in the June 20, 2011 filing.

miles of distribution pipe that operate at a pressure of 60 psig or less. Of the 6,750 miles of gas transmission pipe, approximately 5,800[4] miles meet the definition of a Department of Transportation (DOT) Gas Transmission pipeline. See 49 C.F.R. § 192.3. By comparison, Southern California Gas Company, the nation's largest natural gas transmission and distribution utility by customer count, has approximately 3,989 miles of high pressure gas transmission pipeline. (GTH-49.)

[4] See 2009 PHMSA F 7100.2-1 forms, Pacific Gas and Electric Co (operator #15007) and Standard Pacific Gas Line, Inc. (operator #18608) (GTH-60).

FIGURE 3B-1
PACIFIC GAS AND ELECTRIC COMPANY
PG&E GAS TRANSMISSION PIPES



PG&E operates both backbone and local transmission lines. Backbone lines are larger diameter pipelines that receive and carry gas from interstate sources. Local transmission lines deliver gas to local distribution networks, from which the gas is delivered to most customers.

As the map below depicts, PG&E's backbone lines extend virtually the entire length of the state.

FIGURE 3B-2
PACIFIC GAS AND ELECTRIC COMPANY
PG&E'S BACKBONE SYSTEM

PG&E's backbone lines extend approximately 850 miles from Topock, California in the south, to Malin, Oregon in the north. Lines 400 and 401 make up the northern facilities of the system, Lines 300 A&B the southern facilities, and Lines 107, 114, 131 and 303 the Bay Area Loop. These backbone lines are large diameter pipelines (30" to 42") with Maximum Allowable Operating Pressures (MAOP) between 475 and 1,140 psig.

Combined, the backbone system consists of approximately 2,000 miles of pipeline, representing 35 percent of PG&E's gas transmission system. There are eight compressor stations along the backbone, five supporting L

400/401/402 and three supporting L 300A&B. These facilities help move gas from the various interstate receipt points to customers throughout PG&E's service territory. The backbone system is primarily maintained by PG&E gas technicians and mechanics assigned to PG&E maintenance facilities, including those at Topock, Hinkley, Kettleman City, Tracy, Los Medanos, McDonald Island, Willows, Burney, Rio Vista and Milpitas.

PG&E's backbone gas transmission pipeline system is designed to transport up to 3.1 billion cubic feet per day of natural gas from interstate pipeline receipt points at the northern and southern California borders, Malin and Topock, respectively, to metropolitan areas and customers within the San Francisco Bay Area, Sacramento and San Joaquin Valley. In 2009, roughly 50% of PG&E's natural gas supply was received at Malin, Oregon from either Canada or the Rocky Mountain areas. (GTH-50.) Approximately 40% of PG&E's natural gas supply originated in the Southwest and was received at Topock, California. Natural gas reserves within California, mostly from the Sacramento Valley, accounted for only 6 percent of PG&E's supply. The small remainder was received at the Nevada/California border from the Rocky Mountain area. These relative percentages vary from year-to-year depending on gas market conditions.

2. Local Transmission System

PG&E's local transmission system consists of approximately 3,600 miles of DOT defined gas transmission pipelines. The local transmission facilities include PG&E's non-backbone numbered transmission lines, distribution feeder mains, and PG&E's six-sevenths interest in the Stanpac Line. To a significant extent, local transmission lines are maintained by personnel working out of one of PG&E's numerous division offices located throughout PG&E's service territory.

Other DOT defined pipeline segments operated by PG&E include underground storage field gathering lines, high pressure customer lines, local gas gathering and station piping, totaling approximately 200 miles. PG&E maintains large gas storage facilities at McDonald Island, Los Medanos and Pleasant Creek. PG&E also has interconnections with additional storage facilities at Wild Goose and Lodi. These storage facilities contribute to the management of the supply of natural gas during peak demand periods.

a. The Growth of PG&E's Gas Transmission System

(1) Early Natural Gas Transmission Lines

PG&E's present-day natural gas transmission system has its beginnings in the late 1920s. In that era, large natural gas reserves were identified and extracted at Buttonwillow and Kettleman Hills. (GTH-1.) In January 1929, PG&E began construction of pipelines that brought natural gas from these fields to various locations, including the Milpitas metering station. At Milpitas, a pipeline was constructed along the eastern shore of the Bay to Oakland and Richmond, while the main corridor was run 44 miles to San Francisco. (GTH-51.) Before 1950, all of PG&E's gas supply originated from sources in California. (GTH-52.) The transmission system in these early days was comparatively small, as the map of PG&E's gas transmission system in 1929 depicts.

FIGURE 3B-3
PACIFIC GAS AND ELECTRIC COMPANY
PACIFIC GAS & ELECTRIC GAS TRANSMISSION SYSTEM 1929

The transmission system expanded and became increasingly integrated in the 1930s to bring additional sources of gas supplies to new customers. By the end of 1930, 183,000 customers in San Francisco had converted to natural gas from heating oil or other sources. (GTH-53.) During the 1930s, additional natural reserves were discovered and extracted at the McDonald Island and Rio Vista fields. (GTH-51.) Transmission lines were constructed to expand system capacity and transport gas from those fields to population centers. By 1936, for example, PG&E had installed a second transmission line from Milpitas to San Francisco. (RH-132.); (GTH-2.)

3. The Post World War II System Expansion

In the 1940s and 1950s, California's population and industrial base grew significantly. Between 1940 and 1953, the population in the forty-six California counties PG&E served grew 73%, from 3,281,874 in 1940 to 5,675,000 in 1953. (GTH-7.) In 1940, there were 658,830 PG&E gas customers in California. (GTH-3.) By 1953, PG&E increased its gas customers by 81 percent to 1,194,098. (GTH-7.) Defense and other industries also expanded, placing increased demands on the system.

PG&E's transmission system grew to keep pace with increased demand. In 1947, PG&E began to purchase natural gas from the Southern California and Southern Counties Gas Companies. (GTH-51.) In 1950, PG&E had completed construction on a 34 inch diameter, 503 mile long gas transmission line running from Milpitas to Topock, California to connect to a third-party interstate line transporting gas from Texas and New Mexico. PG&E's Milpitas to Topock line had the capacity to deliver 400 million cubic feet of gas daily from fields in Texas and New Mexico. (GTH-5.) At the time, the Topock-Milpitas pipeline was the largest diameter pipeline ever constructed for the transmission of natural gas. (GTH-54.) In the few short years between 1947 and 1952, the source of PG&E's natural gas supplies shifted. In 1947, 100% of those supplies came from California fields. By 1952, that figure would shrink to less than 50%. (GTH-6.) Today, it is less than 10%.

In addition to expanding its transmission system, PG&E grew by acquiring smaller utilities, including gas distribution utilities. (GTH-55.) PG&E merged with the San Joaquin Light and Power Corporation in 1938, and Pacific Public Service Company in 1954. In other instances, the company purchased the facilities of other utilities. Thus, for example in 1944, it purchased the butane-air system owned by Coast Counties Gas and

Electric Company in Arcata and subsequently converted the system so that it could supply natural gas.

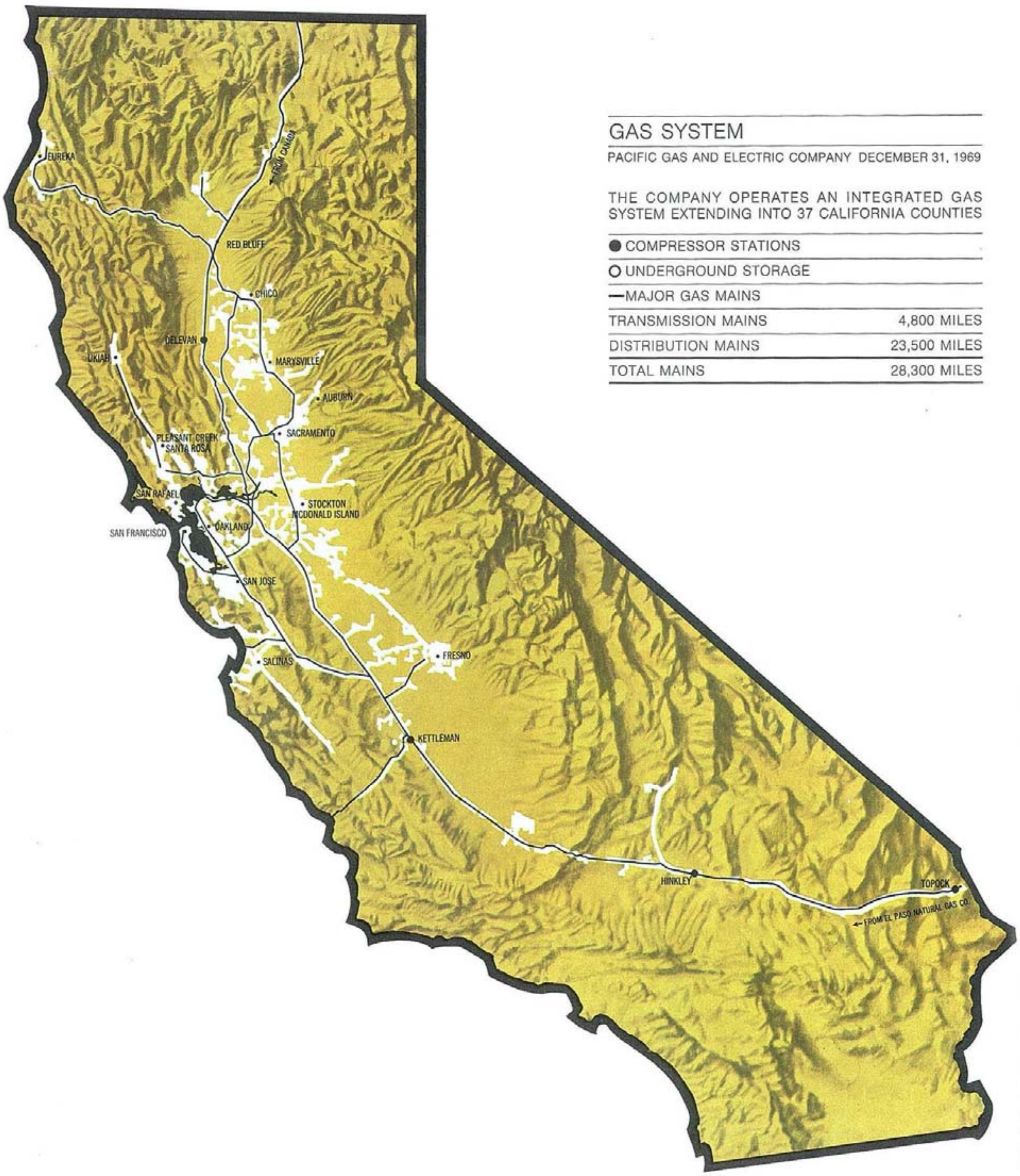
So great was the demand for natural gas that just as PG&E was completing the 503 mile Topock-Milpitas pipeline in 1950, it initiated plans to parallel a portion of the line with an additional 34-inch diameter pipe and to install additional compressor units to increase supply. Construction on the second line began in 1952 and, by 1957, the Company had paralleled the entire 503 miles. (GTH-11.) Daily capacity of the completed Topock-Milpitas pipeline nearly tripled since its first use in 1950. (GTH-56.) By 1957, 70% of PG&E's gas supply originated from fields in Texas and New Mexico. (GTH-11.) This extraordinary post-World War II expansion of gas pipeline facilities, including the installation of the two Topock-Milpitas lines, was part of what was then the largest gas and electric system expansion ever undertaken by any utility in the United States. (GTH-51.)

PG&E continued to expand its gas facilities throughout the 1950s. In 1956, the Company started work on several major projects. It converted a partially depleted gas field in Yolo County into the Company's first natural gas underground storage area. It constructed an 83-mile line in a southerly direction to Sacramento. It built a 175-mile line from northern Sacramento Valley to Eureka, traversing the Coastal Mountain Range. In addition, new reserves of natural gas in Northern California were discovered. (GTH-10.) PG&E's wholly-owned subsidiary, Natural Gas Corporation of California, drilled two additional wells and formulated plans for additional drilling in 1957 on leaseholds adjacent to the successful wells.

The next year, in 1958, PG&E bought the McDonald Island field, located about 50 miles east of San Francisco. (GTH-12.) The field included eleven wells and an 18-inch main that connects the field to the PG&E main gas transmission system. To meet peak demands, the field could put up to 400 million cubic feet per day of gas into the system. (GTH-15.) Construction of Line 400, which connected California to Alberta, Canada, was complete by 1961. The 36-inch diameter line stretched 1,400 miles from Alberta to California. It provided the capacity to transport a maximum of 454 million cubic feet of gas per day, representing over 20% of PG&E's total natural gas supply in 1961.

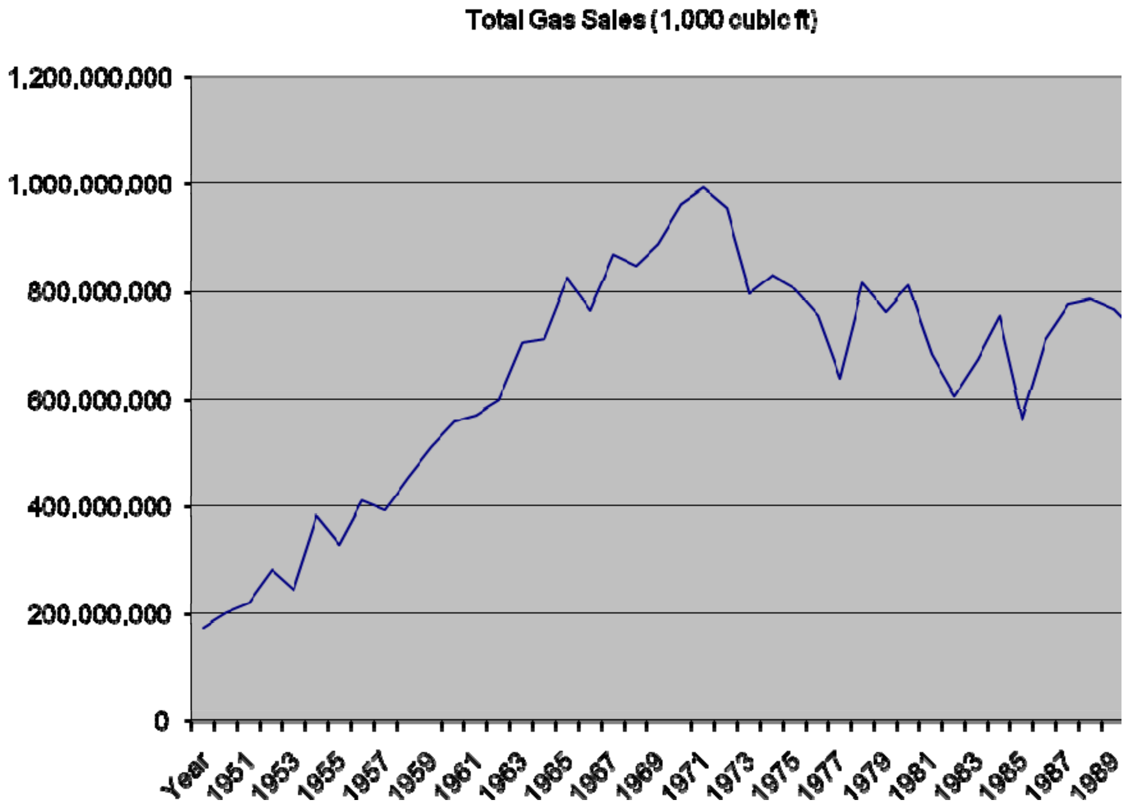
Thus, on the eve of the first federal pipeline safety regulations in 1970, PG&E's transmission system had expanded significantly over the years to include 4,800 miles of transmission mains. The following map depicts the system as it existed in 1969.

FIGURE 3B-4
PACIFIC GAS AND ELECTRIC COMPANY
PG&E GAS TRANSMISSION SYSTEM 1969



The gas transmission system continued to expand after 1970, but at a slower rate than seen in previous years. In the 1970s, the Company contended with a shortage of gas supply resulting in rising natural gas prices. By 1975, PG&E paid an average price of 97 cents per thousand cubic feet for its natural gas representing a 205% increase over the price in 1970. (GTH-29.) The gas shortage and rise in prices were among the factors that contributed to a reduction in the customer demand for natural gas. As the chart below depicts, the upward trend in the volume of gas sales began to flatten and then fall in the early 1970s:[5]

FIGURE 3B-5
PACIFIC GAS AND ELECTRIC COMPANY
PG&E'S TOTAL GAS SALES (1948-1990)



Facing limited gas supplies and increased prices, PG&E expanded its capability to make greater use of its underground gas storage fields. PG&E built additional wells and completed additional pipelines connecting its McDonald Island gas storage fields to the PG&E's gas system. (GTH-28.)

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5 In the mid-1970s, declining gas supply forced moderate curtailments of sales to low priority gas users. (GTH-29.)

The 1980s were marked by several significant events. Natural gas prices started to fall by 1983. (GTH-37.) The national gas market underwent restructuring. (GTH-40.) As described in more detail in Chapter 6C, PG&E formalized a program to replace existing transmission and distribution lines. (GTH-57.) Most of the work occurred in San Francisco and the East Bay, with work also occurring in cities such as Sacramento, San Jose and Fresno. In the late 1980s and early 1990s, PG&E began new pipeline facility construction. In 1991, PG&E opened its newly reconstructed Milpitas Gas Terminal. (GTH-58.) In this same era, PG&E expanded its ability to obtain gas supplies from Canada by constructing Line 401. (GTH-59.) Completed in 1993, Line 401 parallels Line 400.

PG&E has several recent and ongoing local transmission projects to meet increased population growth, particularly in the Central Valley. In recent years, some of the fastest growing regions in the United States, e.g., Placer, south Sacramento, and Fresno counties, are located in PG&E's service territory. PG&E recently completed construction on Line 406, a fourteen mile pipeline in Yolo County, and is now turning to work on Line 407 from Yolo to Roseville. PG&E also expects to soon obtain increased supplies from the proposed Ruby Pipeline, owned and operated by El Paso Corporation, which is expected to supply over 1 billion cubic feet per day of gas from Opal, Wyoming to Malin, Oregon. (GTH-50.)

TABLE 3B-1
PACIFIC GAS AND ELECTRIC COMPANY
MILES BY SIZE

Miles of Gas Transmission Pipelines at year end 2009, as reported in PHMSA F7100.2-1. Miles by nominal pipe size.

Line No.	Unknown	4" of Less	Over 4" Thru 10"	Over 10" Thru 20"	Over 20" Thru 28"	Over 28"	Total
Transmission	0.12	395.78	1,453.28	1,425.79	545.62	1,956.37	5,776.96
Gas Gathering	6.93	22.30	12.67	0.08	0.00	0.00	41.98
Total	**7.05**	**418.08**	**1,465.95**	**1,425.87**	**545.62**	**1,956.37**	**5,818.94**

TABLE 3B-2
PACIFIC GAS AND ELECTRIC COMPANY
MILES BY DECADE

Miles of Gas Transmission Pipelines at year end 2009, as reported in PHMSA F7100.2-1. Miles by pipe by decade of installation.

Line No.	Unknown	Pre-1940	1940 – 1949	1950 – 1959	1960 – 1969	1970 – 1979	1980 – 1989	1990 – 1999	2000 – 2009	Total
Transmission	35.93	267.22	435.94	1,970.67	1,173.66	356.77	549.69	794.17	192.90	5,776.96
Gas Gathering	7.88	0.00	0.42	3.95	16.06	5.41	6.84	1.41	0.01	41.98
Total	**43.82**	**267.22**	**436.36**	**1,974.62**	**1,189.72**	**362.18**	**556.53**	**795.58**	**192.91**	**5,818.94**

Thus, approximately 67% of PG&E's current natural gas transmission system was installed prior to federal regulations taking effect in 1970. This compares to a nationwide average figure of about 61%. Federal pipeline safety laws did not require newly installed gas transmission lines to be piggable until 1994. See 49 C.F.R. § 192.150. More than 83% of PG&E's existing transmission system was installed before 1990. This compares with an industry average of approximately 80%.

Approximately 70% of PG&E's transmission lines run through Class 1 and Class 2 locations – generally described as less populated areas. Figure 1A-6.3 below depicts the distribution of PG&E transmission miles according to class location:

TABLE 3B-3
PACIFIC GAS AND ELECTRIC COMPANY
MILES BY CLASS LOCATION

Miles of Gas Transmission Pipelines at year end 2009, as reported in PHMSA F7100.2-1. Miles by pipe by Class Location.[a]

Line No.		Class 1	Class 2	Class 3	Class 4	Total
1	Transmission	3,484.86	583.91	1,704.47	3.71	5,776.96
2	Gas Gathering	41.93	0.00	0.05	0.00	41.98
3	**Total**	**3,526.79**	**583.91**	**1,704.52**	**3.71**	**5,818.94**

(a) Class 3 and class 4 locations are highly populated areas as defined in 49 CFR § 192.5. "A class location unit is defined as an area that extends 660 feet on either side of the centerline of a continuous 1-mile length of pipeline." Class 3 is a class location unit containing 46 or more buildings intended for human occupancy. Class 4 is any class location unit where buildings of 4 or more stories above ground are prevalent.

As this overview of PG&E's gas transmission system illustrates, PG&E's system is large, long-standing, and diverse. The history of PG&E's expansion over the last century illustrates its incredible growth in the middle part of the last century to serve California's ever-increasing need for natural gas. PG&E's transmission system has evolved from one reliant entirely on intrastate gas sources to one that receives almost all of its gas from interstate sources and transports it throughout a large part of California. PG&E's pipeline construction, maintenance, and operation activities span a long period of time. Its pipelines are diverse in terms of their sizes, age, and characteristics. These considerations influence how PG&E has historically used gas pipeline records, as discussed further below.

CHAPTER 3C

HOW PG&E HAS HISTORICALLY USED GAS PIPELINE RECORDS

1. Records Relating to Reconditioned Pipe

Violation 23 in the Felts Supplement alleges PG&E failed to maintain records to track the reuse of reconditioned pipe. It alleges that these practices violated Section 451 (1954 to 2010) and PG&E's internal policies (1994 to 2010). The allegations rest on a series of claims, many of which lack foundation: (1) the reconditioned pipe in PG&E's system "may not be satisfactory for continued service;"[6] (2) PG&E had a tracking system for salvaged and reused pipe through its accounting records, but "at some time in the past, PG&E apparently lost track of these records;"[7] and (3) in 1979, in what appears to be an intentional effort to eliminate records that show the use of salvaged pipe," PG&E modified its mapping standards.[8]

As explained below, the reuse of reconditioned pipe is not new to PG&E, the Commission, or the gas industry. PG&E long maintained practices for using reconditioned pipe, including practices that take into account the reuse of pipe with known manufacturing threats. Its practices were consistent with the Commission's past understandings and industry practices. While PG&E did not in the past capture data identifying reconditioned pipe in the gas transmission system in its databases, industry standards from the past did not require it to do so or even suggest the practice. Today, PG&E gathers reconditioned and reused pipe data through its MAOP validation efforts. Other actions – such as hydro testing – provide a further measure of safety.

a. The Use of Salvaged and Reconditioned Pipe is Not New to PG&E, the Commission or the Gas Industry

PG&E's past practices address the use of reconditioned pipe. In Standard Practice 520.6-11, Materials and Storages: Handling of Scrap, effective as of April 15, 1964, PG&E established a procedure for separating salvageable from scrap pipe. (Standard Practice (SP) 520.6-

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6 Felts Report at 43.

7 Felts Report at 45.

8 Felts Report at 45.

11, Materials and Supplies – Handling and Storage of Scrap (April 15, 1964) (Ex. 3-2).) In Standard Practice 522.1-1, Reconditioning of Reusable Pipe Removed from Service (Plant Account), effective as of October 1, 1960, the Company set forth billing procedures for reconditioning and provided that all reconditioning work would be undertaken at the Decoto Pipe Yard in Union City. (Standard Practice (SP) 522.1-1 Reconditioning of Resusable Pipe Removed from Service Plant (Plant Account) (Ex. 3-3).)

In a 1988 document entitled "Reconditioned Pipe A.O. Smith Pipe Analysis and Policy Gas Operations,"[9] PG&E sets forth the process for reconditioning A.O. Smith Pipe. That process is likely representative of the processes PG&E used when reconditioning other types of pipe and consists of ten steps intended "to assure a high level of certainty that the reconditioned pipe was in excellent condition when reinstalled." The steps were arranged in the following sequence:

1. Pipe was removed from the ground and sent to Decoto Pipe Yard for reconditioning.
2. Pipe was heated and all coating was removed.
3. Pipe was externally sandblasted.
4. Pipe surface was visually inspected for corrosion and pitting.
5. Longitudinal seams were visually inspected inside and outside.
6. Sections of pipe were removed and discarded if they contained dents, excessive pitting, corrosion affecting the wall thickness, defects in the longitudinal seam, or any other unsafe condition.
7. Oxyacetlyene girth welds were removed and pipe ends were rebeveled.
8. Bell ends were removed and pipe ends were rebeveled.
9. Pipe was wrapped.
10. Pipe was placed in stock for future use.

Reconditioning and reusing pipe has been an accepted practice within the gas industry and among regulators. It was a common practice throughout the industry at least through the 1960s. "Reusing pipe is an

[9] Reconditioned Pipe A.O. Smith Pipe Analysis and Policy Gas Operations (1988) (Ex. 3-4).

acceptable practice as long as the salvaged pipe is inspected and tested as necessary to confirm the integrity of the pipe for reuse within the design requirements for the new installation."[10] As late as 1971, the Minneapolis Gas Company sought clarification from the OPS regarding the use of reconditioned pipe under Section 192.63.[11] The company explained its practice for reconditioning pipe and asked: "Is it permissible to salvage pipe and fittings when the original markings or purchase specifications are not available?" In responding, the OPS acting director did not even suggest that the use of reconditioned pipe was illegal or inappropriate.

The Commission staff has also reviewed and approved for filing numerous past PG&E gas transmission construction projects in which PG&E advised the Commission prior to construction that it intended to install reconditioned pipe. The chart below summarizes at least some of those filings:

[10] Felts Report at 44.

[11] Letter from Minneapolis Gas Company to OPS Re Reconditioned Pipe (March 19, 1971) (Ex. 3-5).

TABLE 3C-1
PACIFIC GAS AND ELECTRIC COMPANY

Date PG&E Notified Commission	Date Commission Responded	Job Description	Reconditioned Pipe Description	Pressure Test Description
June 25, 1964[12]	July 3, 1964[13]	Relocation and reconstruction of Line 109 and 132 due to interstate freeway construction	PG&E: "30' O.D. x .375 wall API 5LX Gr. X52 (reconditioned from Main #132)"	"The reconstructed pipelines will be hydrostatically tested. The minimum test pressure will be 600 psi, equal to 1.5 times the maximum design pressure of 400 psi."
June 29, 1965[14]	July 22, 1965[15]	Proposed construction of 8 mile, 16-inch pipeline extension from feeder Main 301	PG&E: "This pipe was salvaged and reconditioned from Transmission Main #100, originally installed in 1929. PUC: "Since the pipe material used is salvage and reconditioned pipes from Main No. 100 originally installed in 1929, with 33,000 minimum yield and 80% joint efficiency, the maximum allowable operating pressure under Section 107 of General Order No. 112-A will be 412 psig.	"The new pipeline will be hydrostatically tested. The minimum pressure will be 618 psig, equal to 1.5 times the maximum design pressure of 412."
Unknown	August 6, 1982[16]	Installation of 3,664 feet of 24-inch pipe on Line 21 in Petaluma	PUC: "Recondition, Lower and Anchor 10,400 feet of 16 inch Transmission Line 114"	"We have received your letter of June 4, 1982 concerning this project, which involves new construction using water as a test medium."

12 Letter from John C. Morrissey, PG&E, to Public Utilities Commission (June 25, 1964) (Ex. 3-6).

13 Letter from Public Utilities Commission to John C. Morrissey, PG&E (July 3, 1964) (Ex. 3-7).

14 Letter from John C. Morrissey, PG&E to Public Utilities Commission (June 29, 1965) (Ex. 3-8).

15 Letter from William W. Dunlop, Public Utilities Commission to John C. Morrissey, PG&E (July 22, 1965) (Ex. 3-9).

16 Letter from John E. Johnson, Public Utilities Commission, to Daniel E. Gibson, PG&E, Regarding Reconditioned, Lower and Anchor 10,400 feet of 16-inch Transmission Line 114 (August 6, 1982) (Ex. 3-10).

PG&E does not in all instances know where reconditioned pipe has been placed in its transmission system. In the building of its Pipeline Features List (PFL), PG&E has been gathering this information where it is available. But the fact that an operator does not know where it has placed reconditioned pipe would come as no surprise to policymakers from an earlier era. In the years leading up to the initiation of the proceeding in which the Commission adopted GO 112, the Commission had circulated to California operators a staff proposal to impose pipeline safety regulation. The staff proposal included a provision that provided: “No used pipe or pipe of unknown specification shall be used in a pipeline which is designed to operate at pressures of 300 psig or more.”[17] PG&E submitted comments in response, explaining that the ASA standards set forth “complete and adequate procedures” to qualify pipe for reuse and contended that, “[w]ith proper inspection, repair and test, re-use of this material should be permitted.”[18] Subsequently, the Commission transmitted to the industry a revised staff draft that omitted the language that would have prohibited the use of reconditioned pipe or pipe of unknown specification. When, in December 1960, the Commission adopted GO 112, it substantially adopted the ASME standards governing the use of reconditioned pipe.[19]

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[17] Letter from California Public Utilities Commission to Natural Gas Utilities and Interested Parties, with the enclosed Proposed Rules Governing Design, Construction, Testing, Maintenance and Operation of Gas Transmission Pipeline, Section 221 (February 21, 1957) (Ex. 3-11).

[18] Letter from John C. Morrissey, PG&E, to Public Utilities Commission, enclosed with Comments on Staff’s Draft of Proposed Gas Transmission Line General Order, at 3-4 (April 29, 1957) (Ex. 3-12).

[19] ASME B31.8 (1958) included a provision sanctioning the use of salvaged and conditioned pipe. “Removal of a portion of an operating line, and reuse of the pipe in the same line, or at a line operating at the same, or lower pressure, is permitted, subject only to the restrictions of paragraphs A, F and I in 811.27.” Paragraphs A, F and I contained guidelines regarding inspection, surface defects and hydrostatic testing. To this day, ASME B31.8 Section 817 provides for the reuse of properly reconditioned pipe.

b. CPSD Presents No Evidence to Support its Allegation that the Reconditioned Pipe in PG&E's System is Unsatisfactory for Continued Use

In her report, Ms. Felts alleges that in "the process of reviewing PG&E records it has become apparent that PG&E has salvaged and reused transmission pipe now operating in its system that may not be satisfactory for continued service."[20] In making this allegation, she cites to authorization, accounting, transfer and shipping documentation rather than the sort of documents that would be used to maintain detailed material specification.[21] The cited documents cannot support the conclusion that pipe is unsatisfactory.

To the extent that Ms. Felts has identified weld reports showing the reconditioning of pipe, she has assumed that such pipe actually was reused (as opposed to only being sent to the yard for reconditioning). It also does not specify the date the pipe was installed. Pipe installed after July 1961 (if not earlier) would have been hydro tested to a pressure at least 1.25 times its design strength. Ms. Felts has also not addressed information PG&E has produced showing the process the Company used before reusing pipe. Additionally, based on its current understanding of its past practices and industry standards, PG&E believes that as part of the reconditioning process, it removed all field-made girth welds.

c. Felts' Allegation that PG&E Lost Records Pertaining to Salvaged Pipe is Unsubstantiated

Ms. Felts also maintained that PG&E lost records indicating the location of where it had reconditioned pipe. PG&E has not, as best it is aware, lost records about reused pipe. Where older records of this kind are lacking, it more likely is because they were not created. Many job files, however, include records that sometimes demonstrate the use of reconditioned pipe. These records include job estimates, shipping notices and journal entries or vouchers.

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20 Felts Report at 43.

21 PG&E's Response to Records OII Data Request 4-Q22.

d. CPSD Misreads PG&E's Standard – PG&E Did Not Intentionally Eliminate Records Regarding the Use of Reconditioned and Reused Pipe

Ms. Felts further alleges that PG&E deliberately destroyed a tracking system it maintained for reconditioned pipe: "In 1979, in what appears to be an intentional effort to eliminate records that show the use of salvaged pipes, PG&E's drafting instructions in Mapping Standards 410.21-1, section II.3, state 'salvaged and abandoned mains – to be removed from plat sheets.'"[22] Ms. Felts misunderstands the standard. Standard 421.21-1 informs the making and maintaining of distribution plats. It gives direction to erase outdated information and revise plats to reflect street name changes. The section of the standard that the CPSD quotes (see above) provides in full: "Salvaged and Abandoned Mains. To be removed from plat sheets. Consult with supervisory personnel for local operating procedures. S.P. 463 Abandonment of Gas Mains and Services."[23] Information of this kind is removed to avoid confusion. In many instances, information about abandoned pipe was maintained in abandoned line books. The section instructs mappers to remove abandoned and disused mains from distribution plat sheets. It does not, contrary to Ms. Felts' allegations, instruct mappers to deliberately destroy records showing the use of reconditioned and reused pipe in active pipelines.

2. Construction Records (Job Files)

The Felts Report alleges (Violations 16) that from 1987 to 2010, PG&E's job files were missing and disorganized, in violation of Section 451, ASME B31.8, and PG&E's records retention polices.[24] Her report further alleges violations (dating to the 1930s) because PG&E cannot locate certain post-

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[22] Felts Report at 45.

[23] Standard Practice (SP) 420.21-1: Mapping Standards, Gas Department 1"= 100 Plat Sheets, at Section II.3 (Ex. 3-13).

[24] Felts Supplement at 12.

installation pressure test records.[25] The CPSD asserts violations relating to PG&E's management of its job files. The Duller/North Supplement charges (Violation II.A.1) that from 1955 to 2010, PG&E lacked traceable, verifiable and complete pipeline records in violation of ASME B31.8, Section 451, Part 192.709, and GO 112, 112A, and 112B Section 107.[26]

The allegations are wide-ranging and tied only loosely to stated violations.[27] Nonetheless, the Felts and Duller/North reports appear to place at issue: (a) missing strength test pressure records; (b) the process by which PG&E numbers pipeline construction jobs; and (c) the existence of duplicate and decentralized job folders and poor retrieval process. Each subject is address below.

a. Strength Test Pressure Records

The Felts Supplement alleges (Violation 18) that PG&E is missing post-installation strength test pressure records. PG&E's efforts to locate strength test records have been the subject of numerous filings in the OIR 11-02-019 proceeding. (E.g., March 15, 2011 filing, March 21, 2011 filing, May 10, 2011 filing, June 10, 2011 filing, August 26, 2011 filing, January 13, 2012 filing, and May 14, 2012 filing.) The detailed contents of those filings do not need to be restated here. PG&E has taken unprecedented steps to validate the MAOP of pipelines, including the strength testing of 152 miles of pipeline for segments for which the records indicate the segments have common characteristics with the records for the ruptured segment of Line 132. Southern California Gas Company, San Diego Gas and Electric Company and Southwest Gas Company have determined that they too lack or are missing strength test pressure reports for portions of their lines and are taking actions to address those records gaps. As Mr. De Leon (Chapter 1.A), Mr. Howe

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[25] The violation also asserts that PG&E is missing design basis records and references Section 4.3 of the Felts Report for supporting analysis. But except to mention design basis records, Section 4.3 focuses exclusively on post-installation strength test pressure records. Accordingly, PG&E's response does as well.

[26] Duller/North Supplement at 2.

[27] In support of Violation I.A.1 the Duller/North Report cites generally to Chapters 6 and 7 of their testimony. Together, Chapters 6 and 7 run more than 80 pages in length.

(Chapter 1.B), and Mr. Zurcher (Chapter 3.A) explain, the problem of missing or incomplete pipeline records, particularly for vintage pipe, is not confined to California operators.[28]

b. The Job Numbering Process

The Duller/North Report alleges that PG&E's job numbering processes led to significant records gaps and data quality issues.[29] The Duller/North Report points to job numbering in PG&E's ECTS system. ECTS is a document repository PG&E has used to support its MAOP Validation efforts. The way job numbers appear in ECTS does not reflect PG&E's historic job numbering system, or indicate PG&E's future records management direction. ECTS data is being continuously uploaded to Documentum. Documentum (not ECTS) will be the forward-looking repository for job file information.

The weakness of the inferences Duller/North draw from the ECTS records shows itself through examples. In the Duller/North report at Table 6-13, they identify "alpha text only" as a job numbering system. It was not a historic job numbering system, but a data field introduced in the course of the MAOP validation effort. Similarly, an alpha prefix of "P00427" identifies a work break down structure (WBS) number. WBS was a project management control process that PG&E retained to manage large projects.

Even where the Duller/North Report zeros in on PG&E's historic job numbers, it misapprehends how job numbers were created. Many jobs begin not as full-fledged construction projects but as smaller work orders. PG&E's divisions historically have used a four-digit system for numbered work orders of the kind that reflect smaller jobs. That numbering system is very different from the one PG&E uses when

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[28] The date range of violations is too broad in any event. Ms. Felts asserts that PG&E lacks post-installation pressure test records dating to the 1930s. PG&E cannot possibly be "missing" a post-installation pressure test from the 1930s or 1940s. The means to conduct post-installation hydrostatic pressure tests was not widely available in the pipeline industry until the early 1950s. (Shires, T. M. et al, *Development of the B31.8 Code and Federal Pipeline Safety Regulations Implications for Today's Natural Gas Pipeline System*, Volume 1, GRI-98/0367.1, Appendix E, at E-9 (December 1998) (Ex. 3-14).

[29] E.g., Duller/North Report at Sections 6.4.2 and 6.4.9.

initiating larger pipeline jobs. The latter system is chronological. A five-digit job number, for instance, would indicate an older job – one conducted in the 1930s. A longer number generally reflected a job constructed closer in time to the present day.

Another example of how historic job numbers originated in PG&E's system was through acquisition of facilities from another utility. The MIR or Main Installation Record found on some job files is a prefix for 3 and 4 digit numbers for old Coast Counties Gas and Electric facilities. These are different from other types of job numbers reflecting their different origin.

Both the Duller/North and Felts reports identify sequence gaps in job numbering, and infer that these gaps evidence a "missing" gas transmission job file.[30] The inference lacks support. PG&E issues job numbers across the enterprise, which includes jobs for Gas Distribution, Hydro, Electric Distribution and Transmission, vehicle purchases, as well as all lines of business. Gaps between one gas transmission job number and another may reflect intervening gas distribution, electric, hydro and other projects – not necessarily missing gas transmission jobs.

The Duller/North Report additionally alleges that PG&E's treatment of any variation in a job number as a unique job number creates data quality problems that cascade throughout PG&E's information systems. But Dr. Duller and Ms. North confuse historic job numbering conventions with the recent activities involved in the processing of job file documents as part of the MAOP Validation efforts. These are transitory post-September 2010 developments intended to support the MAOP Validation effort, and do not represent "data quality problems."

While the explanations above address the CPSD's misunderstandings of PG&E's job numbering schemes, we acknowledge that there are gaps in our job records, and are addressing those gaps through the MAOP Validation project.

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[30] Duller/North Report, Table 6-14, at 6-59; Felts Report at 32.

c. Duplicate and Decentralized Job Files and PG&E's Retrieval Process

Dr. Duller and Ms. North see in the existence of duplicate and dispersed job folders poor records management practices.[31] Specifically, the Duller/North Report asserts that PG&E did not maintain a comprehensive index or single master source of information, and that information was poorly catalogued.[32]

PG&E has historically performed gas transmission pipeline construction work in field locations across a 70,000 square mile service territory. Construction records have been paper-based. Larger construction projects require project engineers, project managers, field engineers, estimators, mappers, and construction foreman to use and retain copies of these paper records. Each of these individuals may reside in different physical locations hundreds of miles from one another. Understandably, their files were dispersed and at least partly duplicated one another. After jobs were completed, engineers in San Francisco (later Walnut Creek) needed records of the job, as did local divisions or districts, leading to further duplication and decentralization. PG&E acknowledges that even though there were procedures in place, they were not always consistently followed. The fact that copies of job file documents were located in field offices is not only understandable, but makes sense, given limited technology, emerging purpose needs, functional distinctions between divisions and districts, and the size of PG&E's service territory.

PG&E also acknowledges that prior to San Bruno, it did not have a system-wide index of all its pipeline job files. What it did have were distribution and transmission plat sheets that served as graphically displayed indices. They served the operational and maintenance needs of those who used them on a day-to-day basis in the field. In addition, SAP and GIS both provide significant job file information, but neither system was comprehensive. (PG&E's Response to Records OII Request 25-Q3 (Ex. 3-15).) Other tools existed, such as Docutrak and EDMS, but they too were not comprehensive. As a result, PG&E relied

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31 E.g., Duller/North Report at 6-45.

32 E.g., Duller/North Report at 6-79.

heavily on a sometimes cumbersome retrieval process that involved the potential of several searches for relevant documents.

The inefficiencies in the job files retrieval process were the by-product of a paper-based and decentralized records management structure that had served the Company well in an earlier era but has outlived its usefulness. PG&E's GTAM initiative (discussed in Chapter 1.D above) will take advantage of information management improvements to allow PG&E to create and maintain a centralized data management system that will allow for the more efficient retrieval of source documents relating to PG&E's pipeline system.

3. Weld Information/Failure Reports

The Felts Supplement alleges two Section 451 violations relating to weld failure records: (1) 1963 weld failure – no Failure Report (Violation 27); and (2) 1988 weld failure – no Failure Report (Violation 26). In the case of the violations, she maintains that each violation runs from the date of the missing report through 2010. For the analysis supporting these alleged violations, Ms. Felts points to Section 4.4 of her report.

Section 4.4 of the Felts Report does not address either a 1963 or 1988 weld failure. Except for a brief reference contained in Footnote 154, Section 4.4 does not address the topic of weld failure reports at all. Instead it addresses "weld maps and weld inspection reports."[33] The brief reference to weld failure reports in Footnote 154 states:

> 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.

In her Supplement, Ms. Felts added the following language to footnote 154:

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[33] Felts Report at 35.

> During the OII, PG&E was repeatedly asked to produce the technical reports for Line 132 weld failure that occurred in 1963 and 1988 (OII_DR_041-Q05). PG&E has not produced the report on the 1963 weld failure. However, on March 7, 2012, nine months after the issue arose, PG&E produced a cover letter reporting the results of the analysis of the 1988 longitudinal weld failure, but still failed to produce the report referenced in the letter. (OII_DR_041-Q05Supp01Atch01)."[34]

Though not entirely clear, Violations 26 and 27 appear to be supported by footnote 154 (as supplemented with two additional sentences) and appear to reference missing metallurgical reports prepared either by a consultant or PG&E's ATS organization.

a. The 1963 Incident

On January 2, 1963, there was a fire and explosion on Line 109 near the intersection of Alemany Boulevard and Nevada Street in San Francisco. A sample of the broken pipe and weld joint was removed for analysis. We believe that at one time, it maintained a metallurgical report relating to the 1963 incident. As indicated in a letter dated as of March 13, 1963 from PG&E to the Commission (P7-7094 (Ex. 3-16)), We understand that a third-party metallurgist was retained to produce a report on the quality and probable causes of the fracture of the circumferential weld at issue in the 1963 incident in San Francisco. We believe this is because the letter indicates the report was being transmitted to Commission staff. We have not located a copy of the transmitted report (which at this point would be almost 50 years old). Apparently, Commission staff has been unable to locate it in its files either. We have located and provided in this proceeding a significant amount of detailed correspondence between the Company and the Commission regarding the 1963 incident. (Ex. 3-16.) Without question, PG&E would also like to locate the consultant's metallurgical report it previously provided to the Commission. However, absent an allegation

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[34] Felts Supplement at 17 (italics removed).

that a report of this kind must be maintained for the life of the facility (CPSD makes no such allegation), the failure to retain a report the Company shared with the Commission fifty years ago does not rise to the level of a Section 451 violation.

b. The 1988 Weld Inspection Report

Ms. Felts represents that PG&E produced "a cover letter reporting the results of the analysis of the 1988 longitudinal weld failure, but still failed to produce the report referenced in the letter."[35] In fact, PG&E produced three memoranda, two of which reference attached documents. As explained below, the assumption that Ms. Felts seems to draw from this correspondence – an ATS report is missing – illustrates the hazards of trying to assert a violation based on cold record review of events that occurred a long time ago.

The first of the three memoranda PG&E produced as part of its supplemental response to Data Request 41, Question 5, was the memoranda dated December 1, 1988.[36] It is addressed to Golden Gate (one of PG&E's regional offices) from Gas System Design. Gas System Design writes to Golden Gate Region:

> "I have received the Material and/or Equipment – Problem or Failure Report that you prepared describing the failure of the longitudinal welding on 30-inch steel pipe. This report has been assigned to [name redacted] of the Pipeline System Engineering of Gas System Design Department. The evaluation for this report is expected to be completed by April 1989."

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[35] Felts Supplement at 17.

[36] Letter from Gas System Design to Golden Gate (December 1, 1988) (PG&E's Supplemental Response to Records OII Data Request 41-Q5) (Ex. 3-17).

FIGURE 3C-1
PACIFIC GAS AND ELECTRIC COMPANY

Confidential- Provided Pursuant to
Public Utilities Code Section 583

GasTransmissionSystemRecordsOII_DR_CPUC_041-Q05Supp01Atch01

[redacted]

Date: December 1, 1988 File #: 460.21

To: GOLDEN GATE

From: GAS SYSTEM DESIGN

Subject: Failure of Longitudinal Welding on 30-Inch Steel Pipe

[redacted]:

I have received the Material and/or Equipment - Problem or Failure Report that you prepared describing the failure of the longit[redacted]lding on 30-inch steel pipe. This report has been assigned to [redacted] of the Pipe Line System Engineering of Gas System Design Department. The evaluation for this report is expected to be completed by April 1989.

If you [redacted]y questions concerning this report, please contact me on Ext. [redacted]

[redacted]

[redacted]:cm

cc: [redacted] (w/attachment)

62-5218 (rev 3-88)

The second memorandum is dated March 1, 1989.[37] It is addressed to Gas System Design from Technical and Ecological Services (then known as T&ES, a predecessor organization to the Applied Technology Services (or ATS)) organization referenced in Felts'

37 Letter to Gas System Design (March 1, 1989) (Ex. 3-17).

footnote 154. The first paragraph of the March 1, 1989 memorandum references an attachment. It reads:

> "A section of the 30" Bunker Hill transmission line (132) was removed for failure analysis because of a pinhole leak in the longitudinal seam weld (*see attached materials failure report*). X-ray, dye, penetrant, and magnetic particle inspections were performed on the submitted section, but these do not locate the leak. The X-ray and subsequent metallographic examination identified several weld shrinkage cracks but they did not extend through wall. The cracks are pre-service defects, i.e., they are from the original manufacturing of the pipe joint." (Italics added.)

FIGURE 3C-2
PACIFIC GAS AND ELECTRIC COMPANY

Confidential- Provided Pursuant to
Public Utilities Code Section 583

GasTransmissionSystemRecordsOII_DR_CPUC_041-Q05Supp01Atch01

Memorandum

Date March 1, 1989 File # 415 2

To GAS SYSTEM DESIGN

From. TECHNICAL AND ECOLOGICAL SERVICES

Subject. Bunker Hill 30" Transmission Line Failure

PG&E

[redacted]

A section of the 30" Bunker Hill transmission line (132) was removed for failure analysis because of a pinhole leak in the longitudinal seam weld (see attached materials failure report) X-ray, dye penetrant, and magnetic particle inspections were performed on the submitted section, but these did not locate the leak The X-ray and subsequent metallographic examination identified several weld shrinkage cracks, but they did not extend through wall The cracks are pre-service defects, i e , they are from the original manufacturing of the pipe joint

Overall, the X-ray inspection showed the weld to be of low quality, containing shrinkage cracks and voids, lack of fusion, and inclusions Although the actual leak could not be found, it is likely that it was related to one of the weld defects With the leak removed, the remaining pipe should be fully operational again

If you have any further questions, please contact myself or [redacted] at [redacted] or [redacted]

[redacted] kar

03310a/kar29

xc RDKerr/CBScott

Attachment

The third memorandum is dated March 20, 1989.[38] This is a memorandum to the Golden Gate Region from Gas System Design. It provides in substance:

[38] Letter from Gas System Design to Golden Gate Region (March 20, 1989) (Ex. 3-17).

"Thank you for bringing to our attention the problem with the longitudinal weld on the 30-inch steel pipe. The Gas System Design Department has finished processing the Material and/or Equipment – Problem or Failure Report you submitted (GSD received date 11/28/88). A copy of the completed report is attached."

FIGURE 3C-3
PACIFIC GAS AND ELECTRIC COMPANY

GasTransmissionSystemRecordsOII_DR_CPUC_041-Q05Supp01Atch01

Memorandum

Date: March 20, 1989 File #: 460.21

To: GOLDEN GATE REGION

From: GAS SYSTEM DESIGN

Subject: Failure of Longitudinal Weld on 30-Inch Steel Pipe

PG&E

[redacted]

Thank you for bringing to our attention the problem with the longitudinal weld on the 30-inch steel pipe. The Gas System Design Department has finished processing the Material and/or Equipment - Problem or Failure Report you submitted (GSD received date 11/28/88). A copy of the completed report is attached.

If you have any questions concerning this report, please contact me on Ext. [redacted]

[redacted]

cc: [redacted]

Attachment

[redacted]

Among the documents PG&E provided as part of its Supplemental Response to Records OII Data Request 41, Question 5, was a document captioned: "Material and/or Equipment – Problem or Failure Report."[39] The top portion of the document bears a banner indicating it was "TO BE COMPLETED BY FOREMAN AND/OR LOCAL ENGINEERING STAFF." That portion is completed in hand and dated October 27, 1988. The bottom portion of the document bears the banner: "FOR USE BY GAS SYSTEM DESIGN DEPARTMENT." It bears a stamp reflecting it was received by Gas System Design on November 28, 1988, and assigned to the same person referenced in Gas System Design's initial December 1, 1988 memorandum to Golden Gate Region. In the section identified as "FOR USE BY GAS SYSTEM DESIGN DEPARTMENT" is a row labeled: "Evaluation, comments and actions by Gas System Design." In that row, there appears a handwritten note: "Failed section of pipe was inspected. See the attached T & ES Letter dated March 1, 1989." The reference to the "T & ES Letter dated March 1, 1989" appears to be a reference to the second memorandum described above that was prepared by Technical and Ecological Services. This bottom portion of the Material and/or Equipment – Problem or Failure Report" is dated approved as of "March 20, 1989," suggesting that this is the same document that was attached to the third memorandum described above.

[39] Material and/or Equipment – Problem or Failure Report (March 20, 1989) (Ex. 3-17).

FIGURE 3C-1
PACIFIC GAS AND ELECTRIC COMPANY

Confidential- Provided Pursuant to
Public Utilities Code Section 583

GasTransmissionSystemRecordsOII_DR_CPUC_041-Q05Supp01Atch01

75-229
REV. 10/85

S.P. 460.21-7
Attachment 1

MATERIAL AND/OR EQUIPMENT - PROBLEM OR FAILURE REPORT

NOTE: Do not use this form for reporting failures or accidents which result in death, injury, and/or property damage. Also, this form should not be used for reporting corrosion leaks in pipe, or replacement due to normal wear.

TO BE COMPLETED BY FOREMAN AND/OR LOCAL ENGINEERING STAFF
See Attachment 2 of S.P.460.21-7 for Instructions

1. Failed material or equipment LONGITUDINAL WELD ON 30" T.L. 132
2. Location (address) where failure occurred BUNKER HILL DRIVE SAN MATEO City, Co. SAN MATEO
3. Material or equipment details and description of problem or failure A PINHOLE LEAK WAS FOUND ON THE LONGITUDINAL WELD ON 30° T L 132.
4. Service information: Date installed 1948 Other information GM 98015
5. Disposition of failed material Delivered to [redacted] G.G.R. Gas Manager on 11-4-88.
6. Person to contact for information [redacted] Telephone [redacted]
7. Reported by: [redacted] Location Peninsula Region G. G Date 10-27-88
8. Noted by Regional office: By [redacted] Date 881116

SEND ORIGINAL TO MANAGER GAS SYSTEM DESIGN DEPARTMENT - ROOM 2857, 77 BEALE STREET

FOR USE BY GAS SYSTEM DESIGN DEPARTMENT DATE RECEIVED

9. Review assigned to: [redacted] - GSD 11/29/88
10. Copies distributed to: (Gas Dist.)
11. Evaluation, comments and action by Gas System Design: FAILED SECTION OF PIPE WAS INSPECTED. SEE THE ATTACHED TES LETTER DATED 3/1/89.

GAS SYSTEM DESIGN
PCH JRG RCB JAC SYC RFD RER — F/U Date — NOV 28 1988 — KCR KMB ED CM — CIRCULATE — HANDLE — COMMENT — FILE

12. Evaluation comp[redacted] by: [redacted] Telephone [redacted] Date 3/15/89
13. Approved by: [redacted] Date 3-20-89

FEEDBACK*
14. By: OEA Date 3/20/89 Method letter
To:

* IMPORTANT: Feedback must be provided on all Material Problem or Failure Reports, either by letter or copy of completed report. Distribution should be made as outlined in the Guidelines (Supplement to S.P. 460.21-7).

When Ms. Felts refers to "a cover letter reporting the results of the analysis of the 1988 longitudinal weld failure, but still failed to produce the report referenced in the letter[,]" it is unclear what report she believes PG&E failed to produce. Of the two memoranda that reference a report, the memoranda dated March 1, 1989 appears to reference and attach the material failure report initially prepared by the Golden Gate Region which reported the leak. "*A section of the 30" Bunker Hill transmission line (132) was removed for failure analysis because of a pinhole leak in the longitudinal seam weld (see attached materials failure report).*" (Ex. 3-17.) This makes sense because among the documents that PG&E produced was a version of the Material and/or Equipment – Problem or Failure Report for the 1988 leak with only the top part completed.

The March 20, 1989 memorandum from Gas System Design to the Golden Gate Region similarly references the material failure report prepared by the Golden Gate Region. But this time it states it is attaching the completed report. Again this is consistent with the documents PG&E produced. Those documents, as discussed above, include a Material and/or Equipment – Problem or Failure Report, with both the top and bottom sections completed.

Conceivably, Ms. Felts believes that there is a report that was prepared by the Technical & Ecological Services group that PG&E has been unable to produce. But that belief rests on the assumption that the documents that have been described, taken together or apart, reference a Technical and Ecological Services report separate from March 1, 1989 memorandum. That assumption is difficult to corroborate these many years later. An equally (if not more) plausible assumption is that where the completed version of the Material and/or Equipment – Problem or Failure Report attaches the "T & ES letter dated March 1, 1989," it is attaching the only report that T & ES prepared from its analysis of the section of 30 inch pipe that failed in 1988. Certainly, there is one other instance from this era T&ES appeared to provide its report by letter without any supporting laboratory results or other analysis. (P7-7076.)

We regret that we were unable to locate and produce these 1988 leak documents sooner than we did. Even so, we located them. Ms. Felts' Violation 27, which asserts PG&E still has not located the metallurgical report for the 1988 leak, rests on an assumption that more probably than not is inaccurate. Indeed, Ms. Felts searches for the existence of a record that likely was never written.

CHAPTER 3D
EARTHQUAKE RISKS AND THE GPRP

1. The Use of Records in Assessing Seismic Risks

The Duller/North Supplement charges that, from 1992 to 2010, PG&E violated ASME B.31.8 and Section 451 because it lacked the "necessary accurate and readily locatable gas transmission line records" needed to "precisely identify which of its pipelines were more prone to extensive damage during some earthquakes and thereby ensure safe pipeline operation."[40] For supporting analysis, the Duller/North Supplement refers to Section 6.7 of the Duller/North Report. Section 6.7 consists of a self-described "short section that links earthquakes, pipelines and records management."[41] The section is indeed short: it amounts to a page and a half, much of it block quotations from a 1992 FEMA report on earthquake resistant pipeline construction methods. There is no mention of any facts in the discussion – just quotations from the FEMA report and broad conclusory statements.

PG&E's June 20, 2011 filing included an extended discussion of the efforts PG&E takes to address risks from ground movement, including earthquakes. (June 20, 2011 filing, Chapter 6C, at 6C-22-24.)[42] PG&E has long recognized its responsibilities as an operator in a seismically active territory. Although many of its current efforts post-date the 1989 Loma Prieta earthquake, PG&E evaluated seismic hazards before then. Only a few days before Loma Prieta, in fact, PG&E gave a presentation on seismic hazards that could affect the Bay Area transmission system.[43]

After the earthquake, PG&E's Geosciences Department performed a comprehensive seismic review of the pipeline system.[44] Between approximately 1990 and 1992, PG&E added liquefaction and landslide

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[40] Duller/North Supplement at 5 (footnote omitted).

[41] Duller/North Report at 6-91.

[42] PG&E incorporates this section of Chapter 6C from the June 20, 2011 filing by reference.

[43] Golden Gate Region Gas Department, Seismic Study of Gas Transmission Lines: Project Review Meeting Phase 1 Results (October 13, 1989) (Ex. 3-18).

[44] PG&E, Program for Reducing Earthquake Vulnerability of Gas and Electric Systems by the Year 2000 (December 1990) ("1990 Program") (Ex. 3-19).

hazards to its gas transmission corridor maps for its three peninsula transmission lines. It relocated piping under fault crossings to avoid ruptures in the event of future earthquakes and aligned the piping so that it would experience less stress during ground movements. Additionally, PG&E used piping materials and welding techniques that could withstand greater stress levels and, in certain instances, installed shut-off and one-way valves.

In about 2005, PG&E launched system-wide digital geo-hazard maps.[45] Through the use of extensive seismic information provided by the U.S. Geological Services in combination with other data, the Geosciences Department was able to develop a detailed and specific fault crossing list for all of the company's pipe segments. In 2006, PG&E adopted its Gas Transmission Earthquake Plan and Response Procedure, RMI-04. (P3-27406.)

More recently, PG&E has extended its Dynamic Automated Seismic Hazard (DASH) program to gas transmission. The Geosciences Department uses DASH to run detailed scenarios involving eight possible Bay Area earthquakes and generate annual reports. Each scenario includes a "Shake Map" and list of high risk gas pipes and stations associated with that potential earthquake.[46]

The Geosciences Department quantifies the relative priorities of the different scenarios using a value algorithm that factors in fault crossing, liquefaction, slope stability, pipe age, HCA designations, and the Shake Map. The DASH program also automatically calculates the prioritization for pipeline segments after an actual earthquake and electronically sends the information to emergency response personnel. That report specifies what segments have the highest response priority and thus helps personnel in the field prioritize their investigations.

[45] Letter from Christopher S. Hitchcock, William Lettis & Associates, Inc., to Stuart Nishenko Regarding Transmittal and Documentation of Revised GIS Hazard Layers (Liquefaction and Landslide Hazards) for CGT Gas Transmission System (November 9, 2005) (Ex. 3-20).

[46] Gas Transmission DASH Report Scenario Event, M7.0 – Scenario – Rodgers Creek (June 6, 2012).

The gas system's greatest vulnerability in an earthquake is the potential for extensive leakage in the portions of the distribution system that are in liquefaction zones and that are relatively weak because of brittle pipe, weak pipe joints or girth welds, or corroded pipe. (Ex. 3-19.) In the 1989 Loma Prieta Earthquake, PG&E had three transmission line failures (compared to over 80 transmission line failures in the 1971 San Fernando earthquake mentioned in the Duller/North Report).[47] The more extensive damage during the Loma Prieta earthquake was to the cast iron distribution system in the Marina District of San Francisco. The least resistant elements of the gas system were the focus of the Company's GPRP program, which was implemented in 1985 to replace aging pipe throughout PG&E's system.

Section 6.7 of the Duller/North Report does not address the sufficiency of any of these efforts by PG&E to manage the risks associated with ground movement, including earthquakes. Nor does it identify how any of the data analysis and management tools developed by PG&E as part of these efforts are in any way deficient. Nor does it identify the specific regulations that PG&E violated: the Duller/North Report points generally to Section 451 and the ASME standards, but fails to cite a single provision governing ground movement preparedness that PG&E failed to meet.

The Duller/North Report references a 1992 FEMA study, but that study highlighted the experience in the 1971 San Fernando Valley earthquake in which the most serious pipeline damage was to an oxyacetylene welded pipeline installed about 1930. Line 132 is not pipe installed in this era and its girth welds are not of this type.

2. Gas Pipeline Replacement Program

The CPSD also alleges PG&E violated Section 451 in carrying out its Gas Pipeline Replacement Program (GPRP). In short, the CPSD alleges that PG&E excluded Line 132 from the GPRP by using the wrong year as the upper limit for its GPRP – 1947 instead of 1948 – when assessing the excavation threat to gas transmission pipelines. The CPSD concludes: "If Line 132 had been included in this program and replaced the San Bruno

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[47] Donald Ballantyne, *The ShakeOut Scenario* (Supplemental Study prepared for the U.S. Geological Survey and California Geological Survey), at 1 (May 2008) (Ex. 3-21).

rupture and fire could have been avoided."[48] However, this claim is without merit, as Segment 180 and sections of Line 132 built in 1948 did not meet other criteria in the GPRP, and would not have been replaced regardless of the cutoff date.

PG&E launched the GPRP in 1985. The purpose of the program (as it related to transmission) was to replace transmission pipe that were welded using oxyacetylene (Oxy-butt), bell-bell chill ring (BBCR), or bell and spigot (BLSP) girth welds. These girth welds were particularly susceptible to ground movement-related failure (e.g., earthquake, landslide). A report prepared by a former employee (and cited by the CPSD) indicates that the scope of GPRP was limited to replacing transmission pipe installed in 1947 and prior years.[49]

Despite the fact that Line 132, Segment 180, was constructed in 1956, it would not have been a candidate for replacement under the GPRP. The girth welds on Segment 180 were constructed using the beveled-edge configuration, and the weld was made using the shielded metal arc welding process. This configuration and welding method is superior to Oxy-butt, BBCR, and BLSP girth welds, and does not exhibit the same susceptibility to ground movement-related failure. Therefore, even if the scope of the GPRP program included pipe constructed during 1956, Segment 180 would not be considered for replacement. Similarly, the 30-inch diameter portion of Line 132 built in 1948 on GM 98015 was constructed using the same beveled-edge shielded metal arc welding technique. Regardless of the upper limit of pipe replacement under GPRP, neither Segment 180, nor any other section of Line 132 constructed in 1948 using 30-inch pipe, would have been considered for replacement under the GPRP.

[48] Duller/North Supplement at 4.

[49] Duller/North Report at 6-49.

CHAPTER 3E
INTEGRITY MANAGEMENT AND RECORDS

In several sections of her revised testimony, Ms. Felts faults us for missing records and inaccurate information in GIS, claiming that these recordkeeping issues prevent us from operating a functional integrity management program.[50] However, and as discussed in the testimony of John Zurcher (Chapter 3A), the integrity management rules and ASME B31.8S (adopted by reference) were drafted in full contemplation of the fact that operators would not possess complete records, particularly for pipelines that had been built prior to state and federal recordkeeping requirements or that were acquired from another operator. In consideration of the anticipated data gaps, the rules were drafted with provisions for the use of conservative, assumed values, and provided operators with prescriptive measures to be taken when data elements were unavailable. (Chapter 3.A.) Additionally, Ms. Felts identifies several record types (x-ray film, weld maps, and operating pressure history for the life of the pipeline) that are not required to be maintained under 49 C.F.R. Part 192, and that are not required data elements under integrity management rules. While we acknowledge the importance of thorough and complete data gathering, and have implemented several processes to enhance the quality of our pipeline specification, maintenance, and operational data, we do not believe that any of Ms. Felts' charges prevented us from maintaining a functional integrity management program.

1. Most Information in Pipeline History Files Exists in Pipeline Survey Sheets, GIS, or Job Files

Ms. Felts claims that our integrity management program suffers due to the fact that we no longer maintain pipeline history files, and contends that we are missing an unspecified number of job files. PG&E discusses CPSD allegations regarding job files in Chapter 3.C. above. Due to the duplication of the pipeline history file data in other locations, including in hard copy pipeline survey sheets and electronically in our GIS, neither of these assertions affect our integrity management program.

As discussed more fully in Chapter 2.A above, pipeline history files were, as the Duller/North Report characterized them, "really a secondary

[50] Felts Report §§ 4.1, 4.4 and 4.5.

source of information,"[51] as the information in the pipeline history files was centralized in pipeline survey sheets, and subsequently imported into our GIS database, which serves as a primary source of information in the integrity management program. Additionally, the documents in pipeline history files were themselves copies of other documents located in GM or Work Order job files. Our integrity management program has been able to rely on the data in GIS (itself sourced from pipeline survey sheets) and, where necessary, job files. Where information is not available in GIS or in job files, federal rules and ASME B31.8S provide for the use of conservative, assumed values.

2. Weld Maps, X-Ray Film and Inspection Records Are Not Necessary for Integrity Management Program

Ms. Felts asserts that our integrity management program was deficient because we do not maintain all weld maps and weld inspection records. The premise of her assertion is that these records comprise "key pipeline data for the integrity management risk assessment model."[52] In the Felts Supplement, CPSD alleges violations of 49 C.F.R. sections 192.241 and 192.243, Section 451, Article II Section 13(b), and ASME Section B31.8.[53] These violations span from 1930 to 2011. The regulations regarding weld inspection practices, as well as corresponding recordkeeping requirements have changed over this 81 year period, as have PG&E's practices to comply with these requirements. Contrary to Ms. Felts' beliefs, weld inspection reports are not key data for integrity management risk assessment models, but rather play a limited role in the assessment of construction threats.

Prior to 1961, neither industry standards nor government regulations specifically required records of weld inspections to be kept for any period of time. Prior to 1955, industry standards merely called for visual inspection of welds for general workmanship concerns, with provisions for destructive testing of welds where a "reasonable doubt" regarding the excellence of workmanship existed. (E.g., ASA B31-1935 § 524, ASA B31.1-1942 § 524, ASA B31.1-1951 § 524.) In 1955, the ASA Standard Code for Pressure

[51] Duller/North Report at 6-47.
[52] Felts Report at 35.
[53] Felts Supplement at 13.

Piping, Section 8, was amended to provide, for the first time, for the non-destructive testing of girth welds through radiographic, magnetic particle, or other acceptable method. (ASA B31.1.8-1955 § 828(a).) This code left the number and location of welds to be examined to the discretion of the operating company, and did not specify any recordkeeping requirement.

General Order 112, implemented in 1961, introduced the first recordkeeping requirement related to girth weld inspections. GO 112 called for a percentage of girth welds to be made on a sampling basis, with the frequency of inspection based on the class location, status as a tie-in, tap, or repair weld, or presence at a river, highway, or rail crossing. (GO 112 § 206.1 (1961).) The General Order also indicated that "[a] record shall be made of the results of the tests and the method employed[,]" but did not specify any retention period. The inspection frequency and recordkeeping requirements were further modified in 1971 by General Order 112-C, which adopted federal regulations set forth in 49 C.F.R. Part 192. This included section 192.243(f), which increased the weld inspection frequency, requiring all welds in Class 3 and 4 locations to be non-destructively inspected. This section also specified that a record be made showing by milepost, station, or geographic feature, the number of girth welds made, the number tested, and the number and disposition of rejects. General Order 112-C stated, for the first time, that this type of record should be retained for the life of the pipeline. (49 C.F.R. § 192.243(f).) This requirement persists in the federal regulations through the present day.

Following implementation of General Order 112, we implemented Standard Practice 1605 in 1963 to comply with the new regulatory requirements for weld inspection and documentation procedures. This Standard Practice called for us to inspect, through radiographic or other methods, at least the minimum percentage of girth welds set forth by GO 112. It also required inspection results to be recorded on a standard inspection report, which was to be maintained for the life of the pipeline facility in the pipeline construction job file. (P2-1286.) Standard Practice 1605 was renamed as Gas Standard and Specification (GS&S) D-40 in 1976 (P2-1287), and has been updated as necessary to ensure that PG&E's girth weld inspection standards meet regulatory requirements. The revision of D-40 in effect in September 2010 was provided as P2-1296 to PG&E's June 20, 2011 Response.

As suggested by Standard Practice 1605 and GS&S D-40, our practice has been to conduct inspections of girth welds on a frequency that meets or exceeds minimum requirements set forth in regulatory requirements. Results of these inspections were summarized on standard weld inspection reports that listed the location, commonly by geographic reference, the number of welds inspected, and the number and disposition (e.g., repair, replace) of welds that did not meet code requirements regarding weld acceptability in effect at the time. (E.g., API 1104.) In response to Commission directives issued in this proceeding, we reviewed tens of thousands of weld inspection reports that had been gathered as part of our MAOP Validation effort, eventually producing several thousand of these documents that were responsive to Paragraph Seven of the Commission's directives. (P7-0048 through P7-6935.) Contrary to Ms. Felts' conclusions that "few weld records can be found in PG&E job files,"[54] the volume of documents reviewed (and identified as a unique document type in PG&E's ECTS database) demonstrates that our practice has been to retain these types of records.

Ms. Felts also faults us for failing to retain weld maps, claiming that such records would "normally be a source of key pipeline data for the integrity management risk assessment model" and "would provide invaluable information to PG&E in its current efforts to locate and evaluate welds."[55] Ms. Felts includes a sample weld map, but the report does not provide any description or indication of what information present on the map we would use in our integrity management program.[56] Weld maps provide very limited information, other than limited geographic information relating to each girth weld. Weld maps are not identified in 49 C.F.R. Part 192 as a record type that must be created, reviewed, or retained as part of any construction, maintenance, or integrity management process. Furthermore,

54 Felts Report at 34.
55 Felts Report at 35.
56 Felts Report at 35, Figure 4.

Ms. Felts cannot point to any recordkeeping requirement relating to weld maps. (PG&E's Response to Records OII Data Request 4-Q37 (Ex. 3-22).)

From an integrity management perspective, information relating to the integrity of girth welds is relevant to consideration of the presence of a construction threat. Construction threats, such as wrinkle bends, stripped threads or broken couplings, and brittle girth welds (such as those constructed with oxyacetylene), do not present an integrity issue on their own. However, the presence of a construction threat in conjunction with the potential for outside forces (ground subsidence, earthquake, landslide) increases the integrity concern. (E.g., ASME B31.8S Appendix A § 5.3.) To address this concern, we integrate data relating to the ground movement potential along with information relating to pipe characteristics that may indicate the presence of a construction threat. The pipe data includes information relating to the type of girth welds (oxyacetylene vs. shielded metal arc welding) used, and the joint configuration (e.g., bell-bell chill-ring). This information provides more useful input into our integrity management threat identification process, as the type of weld or joint used is a better indicator of the girth weld's propensity to fail under ground movement-induced loading. Consistent with ASME B31.8S guidance, we perform non-destructive examinations of girth welds when they are exposed during the direct examination phase of in-line inspections or direct assessments to determine whether ground movement or other outside force has caused damage to the girth welds, and make repairs or replacements as necessary. (ASME B31.8S Appendix A § 5.5.)

3. PG&E Maintains Operating Pressure History that Predates Integrity Management

Ms. Felts' claim that the lack of complete operational pressure history for all pipelines in our system (even those built decades before the integrity management rules were implemented) prevents us from properly conducting an integrity management program is not supported by the regulations.

As a general matter, operating pressure records (such as pressure charts and SCADA readings) are not considered life of the facility records to be maintained under Part 192 Subpart L. In fact, to the extent specific records retention guidance has existed, it has generally treated pressure recording instrument charts as subject to finite retention periods.[57] One exception is where operating pressure records are relied upon or referenced when making decisions in compliance with integrity management rules, such as looking at the five year period prior to HCA identification for pipe with a manufacturing seam threat. In that circumstance, the records should be maintained for the useful life of the pipeline.[58] However, given that the Integrity Management rules did not take effect until 2004, they cannot apply to record retention practices prior to 2003. In any case, we maintain pressure data obtained from our SCADA system dating back to 1998 (with the exception of 1999, which was inadvertently and irretrievably lost).

Ms. Felts makes two identifiable claims regarding our operating history data. First, she claims that because we do not maintain operating pressure history for the life of the plant, we cannot give an accurate accounting of pressure excursions above MAOP for any pipeline in our system.[59] However, prior to integrity management rules, operators were not required to maintain records of overpressure events on transmission lines. Indeed, regulations allowed for occasional overpressure events that did not exceed 110% of pipeline MAOP.[60] Implementation of integrity management rules created a new set of considerations for pressure history record retention, but only in regard to specific types of pipe enumerated in 49 C.F.R. sections 192.917(e)(3) and (e)(4). These rules require that an operator limit the maximum pressure in an enumerated pipe segment to no greater than the operating pressure history for the five years that predate identification of a pipe segment as located in a high consequence area, or to conduct a hydro test in the event of a pressure excursion above the highest pressure recorded during the five years. As the rules relating to HCA identification were effective on December 17, 2004, this means that we must maintain

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57 E.g., Regulations to Govern the Preservation of Records of Electric, Gas and Water Utilities, (NARUC 2007 Revision) (treating both Gas Pressure Department reports and Recording instrument charts such as pressure as 6 year records); 18 U.S.C. § 225.3 (specifying the retention period for gas transmission and distribution Recording Instrument Charts, such as pressure).

58 49 C.F.R. Part 192.517.

59 Felts Report at 37-38.

60 49 C.F.R. § 192.201.

operating pressure history back to December 17, 1999. For the most part, our pressure history is available in our SCADA data historian from 1998 through the present day. Therefore, we maintain operating pressure records for the period contemplated by the integrity management rules. The loss of data for the applicable period in 1999 does not negatively affect any integrity management consideration, as recovery of this lost data would only have the ability to increase the highest observed pressure during the five year period (which would raise the level to which these pipe segments could operate without requiring a hydro test).

Ms. Felts' second allegation is based on the claim that we lack an unspecified type of historic operating pressure record needed for integrity management risk assessment models. Ms. Felts indicates that PG&E "must enter a number into the model for each pipeline segment, whether or not there is a factual basis for the pressure selected,"[61] but does not identify what data type she is referring to. We do not know what Ms. Felts is referring to and cannot respond to this assertion without more information.

[61] Felts Report at 38.

CHAPTER 3F
LEAK RECORDS

The Felts Report and Supplement assert two violations relating to pipeline leak records. In Violation 21, Ms. Felts asserts that for a period of time ranging from 1930 to 2010, our pre-1970 leak records were missing, incomplete, and inaccessible in violation of Section 451, Article II Section 13(b), ASME B31.8, and General Orders 112, 112A, and 112B. In Violation 22, she asserts that for the period from 1970 to 2010, our post-1970 leak records were missing, incomplete, and inaccessible in violation of Section 451, Article II Section 13(b), ASME B31.8, and General Orders 112, 112A, and 112B. To support these allegations, she points to section 4.6 of her Report.

The Duller/North Report also contains an allegation regarding leak data. It asserts that "PG&E has failed to maintain a definitive, complete and readily accessible database of all gas leaks for their pipeline system as it has failed to routinely migrate all historical leak information from management system to management system."[62]

Together, the Felts and Duller/North reports appear to make three allegations: (1) our leak data is inaccessible; (2) our leak data is missing or incomplete; and (3) the leak data is needed for pipeline safety purposes, including risk assessments. Below, we provide an overview of how we have historically maintained leak data, and then respond to each of the allegations.

1. How We Historically Maintained Leak Data.

Over the past 55 years, we have documented the discovery and repair of gas leaks in the Leak Repair, Inspection, and Gas Quarterly Incident Report (also referred to as an "A-Form" and previously known as a "Leak Test Report" and "Pipe Shut Down" record). An A-Form constitutes our field report of observed conditions relevant to gas transmission leaks, including leaks on welds. The document is filled out by field personnel responsible for leak detection, inspection, and repair. The form has evolved to call for field employees to gather a substantial amount of data including pipe specifications, soil type, cathodic protection, and external pipe condition. This evolution has been spurred both by our recognition of the need for

[62] Duller/North Supplement at 5.

more detailed leak information and by changes in regulatory reporting requirements. We produced the earliest-located revision of this document (dating back to 1979) in our June 20, 2011 OII response as P2-1152.

With few exceptions, we have retained A-Forms either in job files or in separate files located at approximately 70 of our local offices. In the course of this proceeding, we have been collecting and digitizing A-Forms from local offices, as well as A-Forms stored in job files (collected as part of our MAOP Validation Effort). Thus far, we have collected, digitized, and stored over 30,000 documents in the Documentum database.

In the 1970s, we began to enter information from our A-Forms into electronic recordkeeping leak systems. In the early 1970s, we developed a mainframe computer program to track leak repairs across the service territory. Field personnel transmitted leak and repair data to this central database on a monthly basis.

In the late 1980s, we developed a program called PC Leaks to decentralize the data collection efforts of the mainframe program. Local PC Leaks systems were set up at the division level. If a division had multiple districts, each district would have a PC Leaks system; and if a district had multiple offices, each office would have a system. Employees entered leak information directly into these local systems. Once a month, programmers uploaded information from the local PC Leaks systems to a mainframe database system. The mainframe held information indefinitely. The local systems held information until they reached capacity, if ever.

In 1999, we developed a new leak and repair tracking database called the Integrated Gas Information System (IGIS). We migrated data for open leaks (that is, leaks that had not yet been repaired) from PC Leaks to IGIS. IGIS improved on our previous PC Leaks and Mainframe Leaks systems by allowing IGIS users to access all leak data across PG&E's service territory (whereas PC Leaks was a desktop application that could only provide data entered at the local office).

IGIS allows us to record, update, retrieve, and report information regarding gas leak locations, readings, repairs, incidents, inspections, and dig-in data for all gas transmission and distribution facilities. These IGIS capabilities also apply to gas pipe inspections not associated with gas leaks.

IGIS includes a "Leaks" module and an "Incident Data" module to differentiate between leaks and dig-in incidents. IGIS is capable of producing numerous types of reports to display leak status and history data. Among other things, we use data from the IGIS system to record and report gas incident data as required by GO 112-E (and produced in Gas Quarterly Incident reports).

Although IGIS is a source for leak information used in our Integrity Management program, the decisions around the migration of data and functionality from the mainframe and PC Leaks to IGIS predated ASME B31.8S and related federal integrity management regulations. Prior to issuance of ASME B31.8S and integrity management regulations, operators were not explicitly required to conduct trending analysis using historic leak data. As a result, there was no identifiable compliance-related reason to integrate large volumes of historic leak repair data into a new database.

In addition to IGIS, we maintain some leak data in our GIS. Our GIS contains transmission leaks from three data sources. One source is pipeline survey sheets, which contain indications of historic leaks. The second source is IGIS data, which represents the majority of the leaks in GIS. IGIS data is queried for transmission indications and mapped spatially after analysis of the repair information confirms the leak is on a transmission pipeline. The third source is the A-Form, which parallels IGIS after the time periods outlined previously.

2. The Accuracy and Completeness of Leak Data

Ms. Felts alleges that A-forms have "changed over time so that the historical record is inconsistent."[63] While we agree that the format and information called for by A-Forms have changed over time, these changes reflect evolving industry awareness regarding the importance of data that can be obtained from leak records, and changes to regulatory reporting requirements.

We have historically used A-Forms as a source of data from which to complete annual reports, such as those required in PHMSA 7100.2-1, which asks operators to provide (among other items) the number of leaks in certain

63 Felts Report at 40.

specified categories that have occurred on natural gas transmission and gathering lines during a given reporting year. Over time, these reporting requirements have required increased leak data granularity. For example, in the 1970s, PHMSA reports identified five potential categories of leak causes: corrosion, outside forces, construction, materials, and other. During much of the mid-1980s through the 1990s, the PHMSA reporting requirements combined construction and material-related leaks into a single category. In the early 2000s, PHMSA increased the specificity of reporting requirements, requiring operators to quantify leaks in the following categories: corrosion, natural forces, excavation, other outside forces, material and welds, equipment and operations, and other. Following the San Bruno incident, further modifications to these reporting requirements were finalized, requiring operators to identify leaks caused by external corrosion, internal corrosion, stress corrosion cracking, manufacturing, construction, equipment, incorrect operations, excavation damage, vandalism, natural force damage, other outside force damage, and other. These changes in reporting requirements demonstrate the evolving industry and regulatory awareness of the need to identify leak causes with more particularity. The evolution of PG&E's A-Form illustrates our awareness of this need.

Additionally, Ms. Felts claims that our A-Forms were poorly managed, inconsistent, and incomplete. While we share Ms. Felts' concerns regarding the completeness and accuracy of data in some A-Forms, we believe that Ms. Felts' limited analysis does not justify the conclusion that our leak recordkeeping practices have violated regulatory requirements for the last 80 years. Ms. Felts points to a 2006 External Corrosion Direct Assessment pre-assessment attachment for her conclusion that our leak records are inconsistent and incomplete. The attachment identifies the mile point locations of 13 leaks on a segment of the line being assessed, but notes that the causes of the leaks were listed as "unknown (not on A Forms)." (P3-24119.) It is inaccurate to make such broad generalizations about the quality of data contained on A-Forms based on this limited analysis.

The leak data that appears to have been gathered for the 2006 ECDA is provided in attachment P3-24137. The attachment contains a mixture of

GIS leak data outputs and hardcopy A-Forms. Most of the 13 leaks identified in the 2006 pre-assessment attachment appear to have been leaks derived from the GIS leak data from pipeline survey sheets, rather than A-Forms or IGIS. As described above, these historic leak records contain limited information other than the year and location in which the leak was discovered. In contrast, the hardcopy A-Forms that appear to have been gathered as part of this project contain sufficient information to identify the leak source and leak cause. Even so, we recognize the importance of making leak records more accessible and, as discussed above, have undertaken an effort to gather and digitize all hard copy leak records in a central database.

3. The Accessibility of Leak Data for Risk Assessments

Our past decisions not to integrate all leak data into electronic databases were not made in a vacuum. As Bechtel's 1995 Review of the Transmission Priority Analysis (1994) Revision for the Gas Pipeline Replacement and Rehabilitation Program demonstrates, we considered integrating leak data in the mid-1980s as part of the GPRP. The decision was made not to do so. Bechtel summarized the thinking as follows:

> When the GPRP program was originally developed, it was recognized that it would require a large database to collect leak histories of all pipeline segments in order to identify leak cause variables and statistically correlate these variables to actual occurrences. It was concluded that a purely statistical approach to leak quantification was not feasible since it would be inaccurate (leak history data is not detailed sufficiently to establish a correlation) and prohibitively time consuming (due to the very large sample size required). Thus, in lieu of a statistical rendering of leak histories, relative probabilities were based upon cumulative leak history and engineering judgment.
> (P3-20038.)

Leak data is also relevant under Integrity Management principles, but not in the way that Ms. Felts asserts. Leak records are only required data elements for consideration of time-dependent threats, such as external and internal corrosion. They are not required elements for assessing manufacturing threats. (ASME B31.8S, Appendix A.) While leak data is relevant to integrity management processes generally, our inability to locate records relating to a 1988 leak identified on an A-Form as a “longitudinal weld defect” did not factor into the manufacturing threat analysis for Line 132 because, based on sound engineering analysis, there was no need to do so.

The leak record for this 1988 leak indicates that the leak was a “longitudinal weld defect” located at approximately mile point 30.5. Additional investigation into the leak, carried out by our Technical and Ecological Services group (TES, now known as Applied Technology Services, or ATS) revealed that the leaking section of pipe contained several imperfections in the longitudinal seam. However, despite the use of several investigative methods, the leak was too small to be located. This type of “pinhole” leak, while rare, is not unexpected in DSAW pipe. Indeed, DSAW pipe is viewed across the pipeline industry as safe and reliable, with a proven performance history. Incidents due to seam weld defects on DSAW pipe are rare. Prior to San Bruno, each pipeline incident involving a DSAW weld that was reported to PHMSA involved pinhole leaks. None resulted in longitudinal tears or rupture of the pipe. In short, pinhole leaks, such as the one identified in 1988, do not constitute a pipeline failure under integrity management rules, and are not evidence of a manufacturing threat. Had we located leak records relating to this leak, it would not have put our Integrity Management engineers on notice of the need to inspect the longitudinal seam of pipe used or similar to that installed on Line 132 in 1948.

CHAPTER 3G
THE QUALITY OF GIS DATA

Ms. Felts also alleges violations relating to our GIS data. In Violation 24, she asserts that from 1974 through 2010, there was "bad data in Pipeline Survey Sheets and GIS," resulting in violations of Section 451 as well as our "internal policies requiring retention of eng. records."[64] To support this violation, she cites to Section 5.0 of her report, which states that incorrect, assumed, and missing data entries limits the use of GIS in our Integrity Management program. While we recognize the importance of complete, accurate, and reliable pipeline records, our use of GIS, premised upon prior pipeline survey sheets (and the accuracy of the data therein), is consistent with industry practice. Additionally, our use of conservative, assumed values is consistent with regulatory and industry consensus standards. Contrary to Ms. Felts' claims, the data in our GIS does not constitute a violation of Section 451, and the GIS (which is not our system of record for pipeline records) did not replace engineering records.

We began to develop our Gas Transmission GIS in the early 1990s to enhance our capabilities in managing assets and facilities, and to provide a central access point for pipeline information within many groups in Gas Transmission. To populate GIS, we imported pipeline data from existing pipeline survey sheets, and accepted the accuracy of those records. While we have no specific data on the quality control process, we understand from individuals involved with GIS in its initial stages that we conducted a form of quality control process when inputting information into GIS. This included double-checking the accuracy of the transfer and randomly selecting points in GIS to compare back against the survey sheet entry. Mappers also reviewed selected data to identify questionable entries, such as illogical diameter changes. Despite the quality control measures, we are aware that data errors exist within the current GIS system (either from original pipeline data or introduced during the transfer), and have established a process by which field personnel can identify data inaccuracies and update that information in GIS. Our Risk Management Instruction No. 6, Rev. 1 describes the process for notifying the Mapping Group to update GIS when a change needs to be made to the system. (RMI-06, Rev. 1.) Spreadsheets containing the information that needs to be updated are then provided

[64] Felts Supplement at 14.

to Mapping to update GIS. The Mapping Group enters any updates from Division into GIS to minimize any confusion in data entry.

Our GIS (and prior to GIS, our pipeline survey sheets) serves as a central point of reference, and provides Integrity Management personnel ready access to information. Where information is missing, our Risk Management Procedures call for Integrity Management personnel to conduct additional data gathering from hard copy records maintained in engineering libraries and in Division and District offices. (RMP-06, Rev. 1.) In the instances where this information cannot be identified, our use of conservative, assumed values in GIS is consistent with regulatory and consensus industry guidance, and does not prevent us from operating an effective integrity management program.

While our GIS serves as a central reference, it does not serve as our system of record for pipeline documents, which are maintained in hardcopy format in job files. However, we recognize the importance of having the information in the reference system be as complete and accurate as possible. In 2011, we began a huge effort to upgrade to a new GIS system.[65] We are in the process of validating pipeline MAOPs and creating pipeline feature lists based on the detailed review of voluminous source records. The product of this comprehensive effort is provided to key groups within the Company, such as Integrity Management and the team leading our Pipeline Safety Enhancement Plan. We are also developing an enhanced GIS platform into which verified and confirmed pipeline information will be integrated. We currently estimate that the new GIS will be complete by January 2013.

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[65] This effort is explained more fully in Chapter 5 of PG&E’s Pipeline Safety Enhancement Plan filed in R.11-02-019.

CHAPTER 3

APPENDIX C

CURRICULUM VITAE OF

JOHN S. ZURCHER

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RESUME OF JOHN S. ZURCHER

FORMAL EDUCATION

Associate of Arts in Engineering Technology
University of Southern Colorado - 1975

Bachelor of Science in Electrical Engineering
University of Colorado - 1977

Master of Science in Business Administration
University of Northern Colorado - 1981

PROFESSIONAL AFFILIATION

Department of Transportation, Technical Pipeline Safety Standards Committee,
1995 to 2001
(Advisory Committee to DOT, appointed by the Secretary of Transportation)

American Society of Mechanical Engineers, B31.8 Section Committee,
1980 to present

NACE International
1993 to present

Gas Piping Technology Committee,
1980 to 2000
(Chairman of Transmission Division, 1986 to 1994)

American Gas Association, Operations Safety Regulatory Action Committee,
1984 to 2001

Interstate Natural Gas Association of America,
1980 to 2001
(Chairman of Pipeline Safety Committee, 1992 to 2001)

Gas Technology Institute, 1993 to 2001
(Chairman of Integrity Maintenance & Systems Operations, 1993 to 2001)

Pipeline Research Committee, International
1993 to 2001
(Co-Chairman of Design and Integrity Management, 1999 to 2000)

Department of Transportation, Mapping Quality Action Team
1994 to 2000

Department of Transportation, Risk Management Quality Action Team
1994 to 2000

MILITARY BACKGROUND

United States Navy Submarine Service - 1970 to 1974
Engineering Department, Auxiliary Division

CONGRESSIONAL TESTIMONY GIVEN

Testified before the Committee on Transportation and Infrastructure, Congress of the United States in 1999 concerning the Reauthorization of the Natural Gas and Hazardous Liquid Pipeline Safety Program.

Testified before the U.S. House of Representatives Committee on Commerce in 1999 concerning the Reauthorization of the Natural Gas and Hazardous Liquid Pipeline Safety Program.

HONORS AND AWARDS RELATED TO PIPELINE SAFETY

Pipeline Research Council International, Inc., Distinguished Service Award - 2002

Office of Pipeline Safety Certificate of Appreciation, Mapping Quality Action Team – 1998

U. S. Department of Transportation Certificate of Special Achievement, Risk Management – 1997

EXPERIENCE

<u>2002 to Present – Principal at P-PIC, Managing Director at The Blacksmith Group</u>

Principal at Process Performance Improvement Consultants, LLC (P-PIC) and Managing Director at The Blacksmith Group. Major areas of emphasis are consulting to natural gas and hazardous liquid pipeline operators and consulting to various natural gas and hazardous liquid trade associations and research organizations.

As a consultant to pipeline operators, expertise is provided in many areas such as design, construction, pipeline integrity management, risk management, security, emergency response, operations and maintenance procedures and standards, pipeline safety regulations, operations and maintenance work processes, and process auditing.

As a consultant to trade associations and research organizations, expertise is provided in basic research, consensus standards development, pipeline safety regulations, pipeline integrity and risk management research, and communications liaison between these entities.

2001 to 2002 – Vice President, HSB Pipelines

Consultant with Hartford Steam Boiler Inspection and Insurance Company (HSB), in the Pipeline Group. Major areas of emphasis were consulting to natural gas and hazardous liquid pipeline operators. In addition, consulting to various natural gas and hazardous liquid trade associations and research organizations.

As a consultant to pipeline operators, provided expertise in many areas such as pipeline integrity management, risk management and emergency response protocols. Additionally, expertise was provided in the areas of operations and maintenance procedures and standards, pipeline safety regulations, design and construction work processes and operations and maintenance work processes.

As a consultant to trade associations and research organizations I provided expertise for the development of many consensus standards. Additionally, expertise was provided in the areas of pipeline safety regulations, pipeline integrity and risk management research, and communications liaison between these entities and all involved stakeholders. I also was the primary author of the Natural Gas Industries Security Practices Report.

1997 to 2001 - Manager, Pipeline Safety, Columbia Gas Transmission

Responsible for the products of a group of engineers and analysts in the areas of Pipeline Safety Compliance, Risk Management, Capital Maintenance Programs, Emergency Response, and the Engineer Training Program.

The Pipeline Safety Compliance Section is responsible for insuring compliance with applicable industry codes, Company standards, and Federal and State Regulations. This includes maintenance of the Operations and Maintenance Manual, incident reporting, crisis communications, code interpretations, compliance monitoring, responding to rule-makings and Pipeline Safety Re-authorizations.

The Risk Management Team is responsible for developing the Companies Risk Management Program. This includes model development for use in planning rehabilitation and other integrity programs, development of the Risk Management Plan for the Company and for developing the program to enter the Company into the DOT Risk Management Project.

The Capital Maintenance Team is responsible for insuring the integrity of the Companies pipeline facilities. This includes the management of the Companies pipeline integrity assurance program, pipeline replacements, pipeline rehabilitation, pipeline inspection including the smart pigging program, and pipeline efficiency improvement projects. The section is also responsible for setting of standards and developing procedures for pipeline operation and maintenance.

The Emergency Response Team is responsible for insuring the proper procedures are in place and that the proper training has been conducted to effectively handle a pipeline emergency. This includes making facilities safe, notification of regulatory agencies, liaison with local emergency response agencies and public officials and implementation of continuous improvement.

The Engineering Training Program provides for the recruitment of recent college graduates and their initial training and internship. This program provides for a structured two-year education of these individuals in order to provide them with a broad knowledge of company operations.

<u>1993 to 1997 - Director, Pipeline Services, Tenneco Energy</u>

Responsible for the products of a group of engineers, consultants, technicians, analyst, and clerical personnel in the areas of Corrosion Control, Pipeline Engineering, Codes and Standards, Risk Management, Systems Applications, and AM/FM/GIS. Corporate Companies include: Tennessee Gas Pipeline Company, Midwestern Gas Transmission Company, East Tennessee Natural Gas Company, Iroquois Gas Transmission Company, and Channel Industries Gas Company.

The Corrosion Control Section is responsible for insuring the protection of the Companies steel infrastructure. This includes setting of standards and procedures for corrosion control, training of personnel, audits of compliance, quality assurance and quality control of all corrosion control activities and records.

The Pipeline Engineering Section is responsible for insuring the integrity of the Companies pipeline facilities. This includes the management of the Companies pipeline integrity assurance program, pipeline change-outs, pipeline rehabilitation, pipeline inspection including the smart pigging program, and pipeline efficiency improvement projects. The section is also responsible for setting of standards and developing procedures for pipeline operation and maintenance.

The Codes and Standards Section is responsible for insuring compliance with applicable industry codes, Company standards, and Federal and State Regulations. This includes maintenance of the Operations and Maintenance Manual, incident reporting, crisis communications, code interpretations, responding to rule-makings and Pipeline Safety Re-authorizations.

The Risk Management Section is responsible for developing the Companies Risk Management Program. This includes model development for use in planning rehabilitation and other integrity programs, development of the Risk Management Plan for the Company and for developing the program to enter the Company into the DOT Risk Management Project.

The Systems Application Section is responsible for administration of the Companies electronic forms and databases for all as-built activities and operational records. In addition the section maintains the house count database, performs annual relief and regulator valve capacity confirmations, and establishes MAOP's for the pipeline system.

The AM/FM/GIS Section is responsible for the design, development and implementation of the Companies GIS System. This system in conjunction with a Work Management System and a Document Management System will provide the necessary platform to move to an integrated Risk Management Program as well as manage the company's as-built records and operational records. The system will be implemented in 1997.

1988 to 1993 - Manager, Engineering, Panhandle Eastern Corporation

Responsible for the products of a group of engineers, technicians, analysts, and clerical personnel to insure that all facilities are designed, constructed, operated, and maintained in accordance with applicable government regulations, industry codes, and Company standards. Corporate companies included: Algonquin Gas Transmission Company, Centana Energy Company, Panhandle Eastern Pipe Line Company, Texas Eastern Transmission Company, and Trunkline Gas Company

Worked on all Company projects involving facility additions and replacements in order to provide quality assurance. Responsible for insuring regulatory compliance with the Department of Transportation, the States in which the Corporation operates in, as well as other local municipalities. Participate in rule-making activities at the Federal and State levels writing regulations and giving testimonies on behalf of the Company, the industry, and engineering associations. Prepare and adhere to capital and operational budgets for the Company and my department.

Responsible for the Corporations AM/FM/GIS System. This system contains the facility data base and graphics elements, which comprise the Corporations mapping systems. These maps and data base are used to insure compliance with the regulations as well as to provide operating personnel with the necessary documents to perform their work.

Responsible for the As-Built Program for the Corporation. This program takes field mark-ups of construction and operating maintenance activities and as-built's the information into the appropriate permanent records.

Responsible for the Corporations Engineering Records System. These record systems contain all necessary records that document engineering activities. The records maintained include those items necessary to prove regulatory compliance as well as the retention of other business-related documents.

Responsible for the efforts of the Corporations Specialty Mapping Program. These specialty maps are used to present graphical information about the Corporations facilities for use by management and several departments within the Corporation.

1987 to 1988 – Consultant

Responsible for the pipeline safety programs for four intrastate operators. The companies were CITCO Refining and Chemical Company, Clarke Refining Company, AMOCO Gas Transmission Company, and Coastal Crude Gathering Company. These programs insure a proper compliance posture with the Texas Railroad Commission and DOT in the areas of inspections and maintenance of the pipeline systems, records and their systems, and design and construction specifications and standards.

1981 to 1987 - Manager, Engineering, Colorado Interstate Gas Company

Responsible for a group of technical personnel to insure that all facilities were designed, constructed, operated, and maintained in accordance with applicable government regulations, industry codes, and Company standards.

Worked on all Company projects involving facility additions and replacements in order to provide quality assurance. Responsible for insuring regulatory compliance with the Department of Transportation, the States in which operated in, as well as other local municipalities. Participated in rule-making activities at the Federal and State levels writing regulations and giving testimonies on behalf of the Company, the industry, and engineering associations. Prepared and adhered to capital and operational budgets for the Company and my department.

Worked on a collateral basis with the environmental group. Resources and workload was common between the two groups. Worked as an environmental analyst under the direction of the Manager, Environmental Services during periods when significant environmental work was done. Worked in areas such as spill prevention planning; environmental permitting; hazardous material handling, transportation, and disposal, and PSD surveys.

In 1982 given the additional responsibility for insuring regulatory compliance for two other subsidiaries, Wyoming Interstate Gas Company and Cody Gas Company.

In 1986 given the additional responsibility for insuring regulatory compliance for three other Coastal subsidiaries, two in hazardous liquid service, Coastal Pipeline Company and Coastal States Crude Gathering Company, and one in natural gas service, Coastal States Gas Transmission Company.

1979 to 1981 - Senior Engineer, Telecommunications, Colorado Interstate Gas Company.

Responsible for the design, installation, and maintenance of telecommunications equipment for the operational communication of data and information. This included microwave, measurement, supervisory control, telephone, and mobile radio systems. Developed state of the art electronic gas measurement systems and environmental monitoring stations.

<u>1977 to 1979 - Field Engineer, Operations, Colorado Interstate Gas Company</u>

Responsible for the construction of facilities for the transportation of natural gas including pipeline and compressor facilities, gas processing facilities, and auxiliary facilities such as instrumentation, automation and control, electrical, and structural/civil. Also responsible for solving operational problems as they relate to equipment and facilities.