TAB 4

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

RECORD RETENTION POLICIES

Pursuant to the Assigned Commissioner and Administrative Law Judge's Ruling Extending Deadlines for Production of Documents and Setting Prehearing Conference (03/24/11), PG&E submits concurrently with this filing "copies of its record retention policy" for the "various categories of documents" requested as of the end date of Request No. 2 (*i.e.*, as of August 2010).[1]

As of August 2010, PG&E's overarching or umbrella retention policy was Utility Standard Policy (USP) 4, "Record Retention and Disposal" (Attachment #1, PG&E Response to OII Paragraph 2 ("P2-1")). As USP 4 explains, "[e]ach [PG&E] officer ensures that records in his or her organization are retained as required by law, regulation, or sound business practices and are disposed of properly at the end of appropriate retention periods." *Id*. at 1. Officers "ensure that their organizations adhere to record retention periods set by relevant laws and regulations . . . . They may set longer retention periods than legally are required in order to meet administrative, operating, or claims-related needs." *Id*. at 2.

Underlying USP 4 are other documents, including the Utility's "Guide to Record Retention" (Guide) (P2-2), which contains more detailed record retention information broken down by operational area. Additionally, PG&E's "Records Retention and Disposal Guidance for Transmission & Distribution Systems" (T&D Guidance) (P2-3) was issued by Engineering and Operations and by Energy Delivery pursuant to USP 4. Finally, retention period guidance is also found within other PG&E gas transmission documents. These documents are being produced as P2-5 to P2-190 along with an accompanying index.[2]

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1 PG&E will produce historic and prior versions of its gas transmission safety record retention policies on a rolling basis pursuant to the rolling production schedule.

2 USP 4 expired in October 2010 and was effectively replaced by Gov-7001S, which PG&E is producing as part of this production for context (P2-4).

TAB 5

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2A

PG&E'S RECORDKEEPING POLICIES AND PRACTICES

1955-2010

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2A
PG&E'S RECORDKEEPING POLICIES AND PRACTICES 1955-2010

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2A
PG&E'S RECORDKEEPING POLICIES AND PRACTICES 1955-2010

This Chapter responds to Directive 2. It supplements Chapter 2 (Record Retention Policies), previously submitted on April 18th. This Chapter discusses PG&E's recordkeeping policies and practices for the period 1955-2010 and addresses Legal Division's request for additional information (June 3, 2011, Prehearing Conference (PHC) Statement).

A. Introduction

OII Directive 2 seeks PG&E's policies and practices relating to the maintenance and retention of various types of safety-related gas transmission records. Specifically, Directive 2 asks PG&E to provide its explanation as to its policies and practices for a 55-year period, from 1955 through August 2010, for:

> A. Maintaining the technical instructions, manuals, and technical maps and drawings, manufacturer and designer specifications and operating and maintenance instructions, as-built documents, and all other original technical documents pertaining to transmission pipelines . . .
>
> B. Maintaining records of operations, including but not limited to gas pressure . . .
>
> C. Maintaining records of leaks, electronic problems, and other transmission pipeline anomalies . . .
>
> D. Maintaining records of all inspections, tests, and safety risk analyses done on transmission pipes . . .
>
> E. Maintaining the records referred to in A-D above in ways that can be identified, accessed, and retrieved efficiently and promptly.

Directive 2 further directs PG&E to identify changes in the relevant policies and summarize the reasons for the changes.

PG&E has maintained a complete set of its applicable document retention policies dating back to before 1955. PG&E has also maintained a large number of its superseded or retired gas transmission record maintenance policies and practices, some dating back to the 1950s (although they were not mandated to be retained for extended periods of time). PG&E provides an overview of these policies and practices in subsection C, below. Attachment 2A consists of tables that (i) summarize the relevant policies and practices, (ii) identify the changes in the policies and practices over time, and (iii) summarize the reasons for those changes.

Directive 2 also seeks information about PG&E's record maintenance practices. As noted above, Directive 2E asks PG&E how its gas transmission safety records are maintained "in ways that [they] can be identified, accessed, and retrieved efficiently and promptly." PG&E responds in detail in subsection D, below.

PG&E's recordkeeping policies and practices have sought to ensure that gas safety records are available to those who use them, namely, maintenance personnel working in the field, operators monitoring the flow of gas in a control room or at a load center, and gas pipeline engineers designing and constructing new pipelines and overseeing the integrity of existing ones. PG&E designed record access and retrieval systems to meet the needs of the personnel who used them. Some systems are now old or aging, and do not take full advantage of newer record access and retrieval technologies. And, some data are missing or were not adequately transferred into the latest versions of data management systems. As explained by Edward J. Ondak (a pipeline safety expert) in Chapter 2B, these are industry-wide challenges. Although PG&E's recordkeeping practices can be improved, they have historically been pragmatic and functional.

B. June 8, 2011 Report of the Independent Review Panel

PG&E is carefully reviewing the June 8, 2011 report that the Independent Review Panel submitted to the Commission. The report includes statements critical of PG&E's data management practices, including this statement:

> While we understand the entire pipeline industry has had challenges in digitizing and systematizing all the engineering design, construction and operating data, we find PG&E's efforts inchoate. **The lack of an overarching effort to centralize diffuse sources of data hinders the**

collection, quality assurance and analysis of data to characterize threats to pipelines as well as to assess the risk posed by the threats on the likelihood of a pipeline's failure and consequences.

Report of the Independent Review Panel San Bruno Explosion, p. 8 (June 8, 2011) (emphasis in the original).

PG&E is evaluating this conclusion (as well as others in the Report). We believe that there is more that PG&E can do to improve the management of information about its transmission pipeline system, and PG&E is committed to taking appropriate actions to confront and overcome the recordkeeping challenges it faces. Over time, PG&E's gas organization has moved from one place to another with the result that some records have been lost, misplaced, or discarded. The gas organization has reorganized several times in past decades, with some functions being moved from one line of business to another. In hindsight, these changes have impacted records management practices. PG&E has developed many records management systems, in different eras of data management technology. Looking back, we see that the Company has struggled to maintain the continuity and reliability of records across these records management systems. These are not excuses or explanations. They are preliminary assessments about the challenges PG&E faces.

PG&E will identify industry experts who will assist PG&E in addressing its record maintenance challenges. The Independent Review Panel's work is central to this effort, and PG&E intends to confer further with the Panel's consultants.

C. Overview of PG&E's Gas Transmission Safety Record Maintenance and Retention Policies

PG&E has long had enterprise-wide document maintenance policies. The current (as of August 2010) governing standard for providing or creating guidance documents is contained in Corporation Standard GOV-2001S, Guidance Documents Standard Rev.0, issued on 07/12/10 (Attachment P2-6). This standard establishes an enterprise-wide framework for writing, reviewing, approving, canceling, and communicating all guidance documents issued by PG&E Corporation and its affiliates and subsidiaries, including PG&E. GOV-2001S is, in essence, a policy that establishes the standards by which other policies are created, maintained and/or superseded.

The distinction that PG&E draws between a policy and a practice is that a policy provides broad direction to the operations on how to perform work; practices, in contrast, are described in guidance documents. For practices, PG&E currently uses three common guidance document types to communicate "what-to-do" and "how-to-do-it": Standards, Work Procedures, and Bulletins. Policies are the overarching direction provided to the business, standards define what needs to be done to implement the policies, and work procedures provide details on how the work is to be performed. Bulletins are used to communicate interim changes to policies or standards between policy and standard revision cycles. In some cases, guidance documents are presented together in a manual or with other supporting documents such as job aids, numbered documents, forms, drawings, and specifications.[1]

1. PG&E's Document Maintenance Policies

PG&E's document maintenance policies have evolved over time and adapted to state and federal regulatory changes concerning gas transmission document maintenance policies. Attachment 2A details PG&E's document maintenance and retention policies related to gas transmission safety recordkeeping, as well as the changes to those policies over time and the reasons for those changes (where such information is available). The policies listed in the Attachment cover many subject areas, but each touches on record maintenance or retention in some way. Until relatively recently (the 1990s), PG&E did not routinely log the changes between and among the versions of its policies, nor did it formally record the reasons for those changes. Thus, in an effort to respond to Directive 2, PG&E has created a

1 Historically, PG&E has had different names for guidance documents, including: Policies, Standards, Design Standards, Guidelines, Work Procedures, Bulletins, Forms, and Manuals. Many of these document types are still in use but are being converted over time to the existing Corporate Standard format and naming convention. In responding to Directive 2, PG&E will refer to all these various document types as "policies."

change log for record-related policies dating back to the 1950s. PG&E has made diligent efforts to make the log (contained in Attachment 2A) as accurate as possible given the passage of time.

2. Document Retention Policies as Applied to PG&E's Gas Transmission Records

Many of PG&E's policies contain record retention instructions. These instructions track or implement regulatory requirements, or impose additional company requirements. Retention obligations during the past 55 years stem from various regulatory sources: PHMSA regulations, FERC regulations, FPC regulations, and Commission regulations adopting or incorporating the federal regulations. The retention and destruction rules of these different agencies are not always easy to harmonize. All of PG&E's retention policies can be found in the accompanying produced materials, which are organized and indexed topically. PG&E's primary, current (as of August 2010 or immediately thereafter) retention policies are listed below in Table 2A-1.

TABLE 2A-1
PACIFIC GAS AND ELECTRIC COMPANY
PG&E PRIMARY POLICIES ASSOCIATED WITH RECORD RETENTION PERIODS FOR GAS TRANSMISSION PIPELINE

Document Date	Title	Attachment P2-#
10/01/2008	Utility Standard Practice (USP) 4, Record Retention and Disposal	P2-228
05/22/2008	Guide to Record Retention	P2-227
04/16/2010	Records Retention and Disposal Guidance for Transmission & Distribution Systems	P2-230
10/01/2010	GOV-7001S: Record Retention and Disposal Standard	P2-233

3. How Document Retention Requirements Relate To PG&E's Gas Transmission Records

The CPUC's Legal Division requested PG&E to discuss its recordkeeping practices by category of records as set forth in its June 3, 2011, PHC statement. Specifically, Legal Division seeks information concerning how and where five categories of records are kept: (i) as-built drawings, documents, and photos; (ii) pipe specifications; manufacturer's operating manuals, and instructions; (iii) operating history of the pipe, including but not limited to pressure; (iv) maintenance and repair history of the pipe; and (v) risk assessments done of the pipe. Below, we outline the retention policies applicable to each of these categories.[2] Section D discusses PG&E's recordkeeping practices generally, by category requested in Legal Division's PHC Statement.[3]

<u>As-built drawings, documents, and photos</u>. Starting in 1961, with the adoption of General Order 112, and in 1970 with the adoption of the federal code, as-built drawings and related design and construction information were required to be maintained for so long as the pipe remained in service. 18 C.F.R. § 225.3, Index No. 21. PG&E's policies have required retention of these types of records for the life of the pipeline.

<u>Pipe specifications</u>. Pipe specification information is generally subject to a retention requirement for as long as the pipe remains in service. 18 C.F.R. § 225.3, Item 21. Pre-existing pipeline facilities were exempt from construction, design, and initial testing requirements when regulations were first introduced. PG&E's internal policies have also required the retention of these sorts of records for the life of the pipeline.

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2 For a full discussion of document retention requirements applicable to gas transmission records, and when the regulations became effective, see Chapter 1, Regulatory History.

3 This is not to say that records, once created, must remain in the same format for all time. As discussed in Chapters 1 and 2B, pipeline safety regulations allow operators to use any recordkeeping procedure that produces authentic records.

Manufacturer's operating manuals and instructions. There are no manufacturer's operating manuals or instructions for transmission pipe. Therefore, PG&E does not have a document retention policy that is directly applicable. For manufacturer's operating manuals or instructions for station components such as compressors and filters, PG&E's practice is to retain these manuals in the facility where the component is situated and centrally in gas engineering records.

Operating history of the pipe, including but not limited to pressure. PG&E understands this request to refer to operating pressure records and other similar records, *e.g.*, operator logs. Under PHMSA subpart L (Operations), these types of records are required to be retained as "records necessary to administer the procedures" set forth in an O&M manual. 49 C.F.R. § 192.603(b). There is no time period specified in § 192.603(b), however, and the retention period would be subject to any specific requirements set forth in an operator's O&M manual. PG&E's internal policies set forth the relevant retention requirements.

Maintenance and repair history. PG&E understands this request to refer to maintenance and repair records of the kind described in the pertinent parts of PHMSA subpart M (Maintenance). Presently, records of repairs made to a segment of pipe (as opposed to other parts of the pipeline system) must be retained for as long as the pipe segment remains in service. Repair records for non-pipe components generally must be maintained for at least five years. Records related to patrols, surveys, inspections, and tests required by subparts L and M of Part 192 are generally subject to a five-year record retention period, or until the next patrol, survey, inspection, or test is completed, whichever is longer. PG&E's internal policies have also required the retention of these types of records for the same periods.

Risk assessments. PG&E understands this request to refer to the integrity management process described in the pertinent parts of PHMSA subpart O (Gas Transmission Pipeline Integrity Management). Subpart O requires retention of records for the useful life of the pipeline in order to demonstrate compliance, and prescribes the retention of specific minimum records. PG&E's internal policies have required the retention of these types of records for the same period as specified above.

D. PG&E's Recordkeeping Practices From 1955-2010

1. Introduction and Summary of Historical Developments

Directive 2E of the OII asks PG&E to explain how it ensures that its gas transmission documents (referenced in Directives 2A-2D) are "identified, accessed, and retrieved efficiently and promptly." In addition to this directive, CPUC's Legal Division has asked PG&E for a description of the location and retrievability of PG&E's gas transmission records.

Historically, PG&E has made pragmatic recordkeeping choices aimed at making important gas safety records available to those who used them: maintenance personnel working with the pipe in the field, operators monitoring the flow of gas at a load center or in a gas control room, and gas pipeline engineers constructing new pipelines or managing or improving existing ones.

Many records have been stored in local divisions and districts because that is where the work is done. Local maintenance personnel have generally needed records to perform specific tasks, *e.g.*, to repair a valve. In contrast, gas operations personnel rely on system-wide operational data, such as real time compressor and regulator station data, but generally do not need detailed information about pipe specifications or maintenance history. The needs of gas pipeline engineers straddle those of maintenance and operations. Engineers need access to system-wide databases to quickly orient themselves when problem solving or when defining the scope of an engineering task, and they need access to more detailed pipeline records when performing underlying engineering projects. PG&E's recordkeeping practices have attempted to provide these engineers with ready access to summary data (Pipeline Survey Sheets, and later, GIS applications) as well as access to detailed, source data contained in pipeline job files.

Some pipeline records are kept longer than others, and some are kept in different forms (*e.g.*, source versus summary form, paper versus microfilm or electronic form). Source and summary paper and other hardcopy records have generally proven durable and reliable when completed properly, and remain part of PG&E's recordkeeping practices.[4] However, PG&E, like many other operators in the U.S., has had to confront the problem of physically storing hardcopy records. See Chapter 2B. Over time, PG&E's business has grown and evolved, and the locations where it conducts business have changed and multiplied. As PG&E relocated and reorganized business units and groups, PG&E moved records from one location to another. At the time of those moves, PG&E personnel made decisions to retain some records and discard others. Those decisions as to which records were necessary to keep, and which could be discarded based upon regulations at the time, were influenced by operational needs, storage availability and cost, engineering judgment, and recordkeeping requirements. In some cases, particularly during the course of relocations or business reorganizations, valuable records had the potential to be lost or discarded. Anecdotal information, coupled with some record gaps, suggest that over the 55 year period covered by the OII, some data were lost, transferred to another form, or discarded.

Electronic recordkeeping may improve (and at times has improved) the retrievability of source and summary data. However, here too there can be a trade off. With the adoption of each data management improvement comes the risk that data may be left behind or mis-entered in the migration process (either through human translation error or through software or ver-

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[4] Everyone is familiar with the power and versatility of modern computer systems. Today's powerful information technology, however, was not available when PG&E first began installing gas transmission pipeline, or even in the 1950s through 1960s, when its gas transmission system expanded dramatically to meet the needs of California's growing population. Thus, in the early years, PG&E's gas transmission recordkeeping was almost entirely paper (or at least hardcopy) based. Job files existed in hardcopy format, as did, *e.g.,* leak logs, leak repair forms, valve maintenance records, and operating pressure records. These practices were consistent with those of the industry, as explained by Mr. Ondak in Chapter 2B. Even today, computers and electronic records have not completely replaced paper records for all purposes.

sion transitions). Compatibility issues during the migration process from one information format to another can also present obstacles. A challenge for PG&E (and for other operators) has been to anticipate the information that will be important in the future and to ensure that that information migrates to new electronic management systems in a durable, reliable, and retrievable form.

Changes to pipeline safety rules have also altered how pipeline records are used, in ways that have strained existing record management and data retrieval systems. As discussed in Chapter 2B. pipeline safety rules have never given much attention to an individual operator's overall recordkeeping procedures. They have generally mandated that records be maintained, and for how long, but without specific guidance as to how records should be maintained. In contrast, these same pipeline safety rules have made sweeping changes to pipeline transmission safety practices, culminating in the adoption of Transmission Integrity Management Program (TIMP) rules in December 2003 (PHMSA subpart O), effective in 2004. With the benefit of hindsight, it can now be seen that TIMP fundamentally changed how PG&E and other operators need to use their pipeline safety records. The change can be summarized this way: Once pipeline operators maintained records so they were available for use in response to a specific event, such as the need to repair or replace a section of pipe. But pipeline operators now also maintain records as part of a proactive effort to manage the integrity of an entire pipeline system. The shift is from a reactive and static records management system to a proactive and dynamic one. TIMP rules created new demands for accessing, reviewing and integrating historical pipeline information and records, in ways that existing recordkeeping systems and practices were neither designed nor intended to address.

PG&E began putting in place more sophisticated records management systems before TIMP. PG&E realizes, however, that it needs to do more to improve its records management practices to support modern pipeline safety practices. It needs to work harder to ensure the durability and reliability of records over time, and it needs to implement records management tools that promote wider and quicker access to, and integrated analysis of, reliable pipeline safety data.

The historical developments in PG&E's gas transmission safety record-keeping, which reflect the general themes identified above, are summarized in the following Table 2A-2.

TABLE 2A-2
PACIFIC GAS AND ELECTRIC COMPANY
PG&E GAS TRANSMISSION RECORDS EVOLUTION, 1955-2010

Date	Development	PG&E Organizational Status or Changes	Record Status
1955	Beginning of the relevant time period for the OII	Most gas transmission engineering (esp. large-scale projects) is centralized in PG&E's San Francisco headquarters Maintenance and construction work is largely done out of field offices Operations work is performed in System Gas Control and in approximately 10 manned "load centers"	Records are maintained in hardcopy format Records search, access, and retrieval functions are necessarily constrained by technological and geographic limitations
1961	GO-112 takes effect; GO-112 requires pressure test information to be kept, on a going-forward basis, for life of facility	Same as above	Records maintained in hard copy format
1968-1969	PG&E creates Pipeline Survey Sheets (PLSSs) that provide in summary form data about pipeline characteristics	Same as above	PLSSs are created and maintained centrally in hardcopy format, and copies are distributed among PG&E local offices Redline updates done in local offices
1970	PHMSA regulations adopted and incorporated into GO-112-C. PHMSA regulations adopt additional recordkeeping requirements, including requirements for "grandfathered" pipe	Same as above	Records continue to be maintained in hardcopy format only

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Date	Development	PG&E Organizational Status or Changes	Record Status
Early 1970s	PG&E develops a mainframe computer system for gas leaks	Same as above	Leak Repair Forms continue to be maintained in hardcopy format, and are the source documents for leak information, but leak repair information is keypunched into the mainframe system. The system enhances archiving capabilities
1980	Operational records are moved from 29th floor of 77 Beale Street, San Francisco to Walnut Creek	Pipeline Operations Headquarters moves out of San Francisco, separating engineering from operations	Records continue to be maintained in hardcopy format. Operations' central library relocates to Walnut Creek Moves require recordkeeping decisions to be made, based on current operational needs, engineering judgment, and recordkeeping requirements
1985	Record storage locations change	Engineering Records Unit moves offices	Engineering Records relocates from 77 Beale to 123 Mission Street (San Francisco) Moves require recordkeeping decisions to be made, based on current operational needs, engineering judgment, and recordkeeping requirements
1984-1988	PG&E implements Supervisory Control and Data Acquisition (SCADA) system	SCADA allows centralized control and monitoring of the gas transmission system, and leads to the gradual elimination of continuous staffing of manned "load centers" and stations	Real-time operations records (pressures, valve settings, etc.) begin to be maintained electronically in the SCADA system

Date	Development	PG&E Organizational Status or Changes	Record Status
1986-1987	PG&E reorganizes its gas organization and reassigns non-backbone transmission design and construction accountability to the local offices	In a corporate reorganization, local gas transmission engineering work is decentralized. Engineering on the numbered transmission lines (the transmission backbone) continues to be performed centrally	Certain local transmission design basis records and plat sheets are increasingly housed in local divisions to facilitate use by local engineers. They continue to exist in hardcopy format Some records no longer managed and updated centrally
1987	Creation of the "PC Leaks" computer system to capture leak information from Leak Repair Forms	Same as above	Hardcopy Leak Repair Forms continue to be the source record for leak information, but the new computer system allows access to electronic summary Leak Repair Form data
1989	Loma Prieta earthquake; storage at Potrero Power Plant ("Sugar House") no longer viable. Record storage locations change	N/A	Records moved from Sugar House to PSEA Clubhouse (at Potrero Power Plant) Moves require recordkeeping decisions to be made, based on current operational needs, engineering judgment, and recordkeeping requirements
1989-1992	PSEA Clubhouse flooded; some records water damaged. Record storage locations change	N/A	Records moved from PSEA Clubhouse to Bayshore/Geneva facility Moves require recordkeeping decisions to be made, based on current operational needs, engineering judgment, and recordkeeping requirements

Date	Development	PG&E Organizational Status or Changes	Record Status
1994	Began consolidation of Gas Control	PG&E consolidates 10 field control centers to 4 terminals	Some records moved from 10 field locations to the 4 terminals; some records moved to central record storage; some records no longer required to be retained are discarded
1993-1994	Workforce Reduction effort	Records and Information Coordinator function eliminated	Some records no longer managed and updated centrally
1994-1995	PG&E begins development of a Geographic Information System (GIS) for its gas transmission pipelines	N/A	GIS is a useful summary of, or portal to, transmission pipeline information. Design and engineering records continue to be the source record PG&E stops updating former hard copy PLSSs with the adoption of GIS, which causes the hard copy PLSSs to become obsolete

Date	Development	PG&E Organizational Status or Changes	Record Status
1995-1996	Some gas engineering documents in San Francisco relocated to Walnut Creek	Centralized Gas Transmission Engineering is relocated to Walnut Creek	Records are moved from San Francisco (123 Mission) to Walnut Creek and to PG&E's Bayshore storage facility; some remain in San Francisco Some records previously stored at Bayshore (such as GM records) are transferred to Walnut Creek Some other job files (*e.g.*, at some stations) are consolidated in Walnut Creek Moves require recordkeeping decisions to be made, based on current operational needs, engineering judgment, and recordkeeping requirements Some pipeline records were misplaced or discarded in and around this time frame
1999	Creation of the Integrated Gas Information System (IGIS) as a result of efforts by the Gas Leaks and Records Subcommittee, a partnership of management, IBEW, and ESC employees	Decentralized engineering of local transmission jobs continues	Hardcopy "A" Forms continue to be the source document for leak information, but IGIS allows improved, enterprise-wide access to leak information. Some PC Leaks data are migrated and some are archived in legacy systems

Date	Development	PG&E Organizational Status or Changes	Record Status
2001	Record storage locations change	Transmission engineering work continues to be divided between the centralized Gas Transmission Engineering (larger jobs) and the local divisions (smaller, local transmission jobs)	Records stored in several locations in Walnut Creek are consolidated into one Walnut Creek location
2003	PHMSA adopts Integrity Management regulations (49 C.F.R. Part 192, Subpart O)	Existing risk management organization begins to incorporate Integrity Management requirements	Integrity Management does not fundamentally alter the types of records stored, but it increases the need to obtain relevant information

2. Overview of the Records Generated From Gas Transmission Activities (as of August 2010)

PG&E here addresses its current (as of August 2010) gas transmission safety records and recordkeeping.[5] Below is a table of the activities PG&E performs on its gas transmission lines and a summary of the records that PG&E generates from those activities. The table summarizes, among other things, the type of record, its function and location, and who accesses the record and for what purpose and in what manner. In response to the CPUC's Legal Division's request, PG&E has organized this response to generally correspond to the categories of documents identified by Legal Division in its June 3 PHC statement.

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[5] Through PG&E's MAOP Validation effort, PG&E has gathered a significant portion of its design and construction records to a central location for purposes of validating MAOP on its HCA pipelines. In Phase 3 of the MAOP Validation effort, PG&E intends to gather the same information associated with its non-HCA pipelines to perform the MAOP calculation. That effort will continue into next year. Given this effort, many of PG&E's job files have moved during the records collection activities associated with the MAOP Validation effort.

TABLE 2A-3
PACIFIC GAS AND ELECTRIC COMPANY
RECORD TYPES CREATED IN CONNECTION WITH GAS TRANSMISSION ACTIVITIES, AS OF AUGUST 2010[6]

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
Records Associated with Design and Construction of Gas Transmission Pipelines[7]								
"Job files" components: Design drawings Engineering calculations and certifications Job estimates Bills of materials Accounting documents Pressure test documents Weld inspection reports Information on pipe covering or coating, or cathodic protection	Yes	Plat maps Pipeline Survey Sheets (PLSSs) Geographic Information System (GIS)	To record original and as-built design and construction data concerning gas transmission pipelines	Created at engineering location, maintained at job site during construction, and archived centrally in Walnut Creek, in records storage in Bayshore facility, in the local offices, and in Pipeline Engineer files	Engineers Estimators Construction personnel Mappers Integrity Management Project Managers	In-Line Inspection (ILI) assessment External Corrosion Direct Assessment (ECDA) Uprating of pipelines Greenfield or Brownfield planning Construction projects To perform threat assessment for integrity management using historical data MAOP validation	Through retrieval of hardcopy files facilitated by Walnut Creek Central Records personnel	Job file numbers are associated with GIS pipeline segments. This association enables personnel to view a transmission pipeline segment, identify the associated job file numbers, and retrieve the original job files

6 Table 2A-3 covers the general record types created in connection with gas transmission activities. Where there is no primary record, the Table displays summary record/analytical tool function and related information.

7 This group of records generally corresponds to "As-built drawings, documents, and photos" and "pipeline specifications" in Legal Division's PHC statement.

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
system (if installed as part of job) Original design class location Manufacturing mill test records (for large jobs) Construction standards and specifications (for contractors) Permitting and environmental records								
Welding personnel qualification records	Yes (hard copy)	Welder Qualifications Database (MS Access)	To record PHMSA subpart (E) welding personnel qualification information	Maintained in PG&E's San Ramon offices by the System Support Process Group	Division and district supervisors and superintendants Transmission Specialists	To monitor and verify qualification of welders	Through an electronic tracking system or hard copy	Not related
MAOP List	Yes	No	To record and update MAOP and MOP and future design pressure information for gas transmission lines	Maintained in PG&E's Walnut Creek offices	Risk and integrity management personnel Pipeline Engineers (PLEs) Other engineers Gas system operators Mappers Estimators Design drafters	To safely operate the transmission system Risk and integrity management and system planning purposes	In hardcopy format and electronically on a shared drive	There is no link between the MAOP list and GIS. The GIS MAOP information is listed by segment, rather than by pipeline

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
Records Associated with Operation of Gas Transmission Pipelines[8]								
Supervisory Control and Data Acquisition (SCADA) records	Yes	No	To remotely monitor and/or control major transmission stations and other gas pipeline equipment in real time	System Gas Control	Gas Control, gas technicians, maintenance and construction personnel, and engineers Design engineers Mappers Estimators Historical SCADA data are used by gas engineers and gas planners Historical data are also used by Integrity Management	To operate gas pipelines in real time In connection with maintenance work To plan for infrastructure upgrades To forecast gas inventory needs and reliability impacts To calculate risk for integrity management using historical data To assist with design To assist with technician troubleshooting of equipment	Electronically, including through a secure SCADA Web Server	Began adding SCADA Points into GIS in 2006
System Gas Control Room logs	Yes	No	To record operations or actions taken by System Gas Control	System Gas Control	System Gas Control supervisors	To conduct Gas Control operations For incident investigations and root cause analyses	Electronically	Not related
Clearance records	Yes	No	To ensure the safety of the general public, company personnel, and pipe-	For clearances that have the potential to affect the overall gas transmission system, clearance forms are	Gas technicians and maintenance personnel System Gas Control	For safe execution of transmission work	Electronically in Gas Control, in hardcopy format locally	Not related

8 This group of records generally corresponds to "operating history of the pipe" in Legal Division's PHC statement.

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
			line assets during work that will affect pressure, the flow of gas, and/or the quality of the line, or the ability to monitor these factors	sent to System Gas Control and also maintained locally For other clearances, clearance forms are maintained locally	Transmission and Regulation (T&R) personnel			
Current class location records	Yes	Yes	To record current class location	GIS	PLEs and other engineers Integrity Management Maintenance schedulers Mappers	In connection with repair or replacement work In connection with PG&E's Integrity Management Program	GIS	GIS is used as the source record
USA one-call tickets	Yes	Yes	To record information from third parties through the USA one-call number	Maintained electronically in the IRTHNet system	Mark and Locate personnel PLEs Damage Prevention personnel Damage prevention process owner (Integrity Management Department)	To perform Mark and Locate work To monitor anything out of the ordinary on a pipeline To identify construction areas and construction activities in connection with risk assessment To assess effectiveness of Damage Prevention program	Electronically through IRTHNet	Not related
Station and Operating Maps & Diagrams	No	Operating Maps & Diagrams are summary tools SCADA	To display station and piping configuration	System Gas Control Gas transmission compressor and regulator stations	System Gas Control Operators Maintenance personnel	To operate stations and valves To process clearances To conduct maintenance	Electronically in System Gas Control Electronically in Gas Transmis-	Links to E-file are contained in GIS

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
				and terminals Local districts and divisions Gas Transmission Mapping	Engineers Mappers	activities Design modifications	sion Mapping In hardcopy format in the local divisions and districts	
Station Equipment Manuals	Yes	No	Manufacturer instructions for operation and maintenance of equipment	Compressor and regulator stations and terminals Walnut Creek Engineering Records	Maintenance personnel Station engineers Transmission Specialists	To operate and maintain equipment	In hardcopy format	Not related
Corrosion Control Records	Yes	SAP and PipeLine Maintenance (PLM) program	To measure and monitor the performance of cathodic protection systems	For backbone transmission pipelines maintained by districts, data are entered directly into PLM database For local transmission lines, data are maintained in local divisions in Cathodic Protection Area (CPA) files, arranged geographically	Corrosion mechanics and technicians Transmission and Regulation (T&R) supervisors and district superintendents Corrosion engineers Integrity Management engineers (ECDA and ILI groups in particular) Corrosion Control process owner (Integrity Management Department)	To monitor cathodic protection systems Used in Integrity Management to aid in assessing the condition of the pipe, and to validate assessments	Through PLM in the transmission districts In hardcopy format (CPA files) in divisions unless division has transitioned to SAP	Not related

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
Records Associated with Maintenance of Gas Transmission Pipelines[9]								
Leak repair records ("A Forms")	Yes	Integrated Gas Information System (IGIS) PC Leaks legacy system (contains historic data) Selected fields from the A form are manually recorded on leak log	To record information regarding leaks and leak repairs To record information regarding the condition of pipeline that is exposed (*e.g.*, when a leak repair is made)	A Forms are stored in the divisions, typically organized by map number / plat number / block number For backbone transmission pipe, A forms are forwarded to Gas Transmission mapping for input into IGIS/GIS For Local Transmission pipe, A Form information is recorded in IGIS by local mappers and input into GIS by Gas Transmission Mappers A Form may reside in job file if created in connection with a specific project	Maintenance personnel Engineers Integrity Management Mappers Regulatory Support & Analysis personnel Leak process owner (Integrity Management Department)	To perform maintenance work To conduct leak repairs To calculate risk for integrity management using historical data	In hardcopy format in the divisions and districts Electronically through the IGIS system Selected data are available electronically through GIS system	Selected data from A Forms are manually entered into GIS by mappers.
Leak logs	Yes	Information from leak log is entered into IGIS, which initiates further action	To record information on leaks and poten-	For local transmission, leak logs are maintained in local	Maintenance personnel (leak surveyors) Maintenance	To perform and track leak survey work	In hardcopy format in the divisions	Leak log information is input into IGIS, and key data are periodi-

9 This group of records generally corresponds to "maintenance and repair history" in Legal Division's PHC statement.

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
			tial leaks observed during a leak survey	division offices	supervisors and superintendents			cally transferred to GIS
Valve and regulator maintenance records	Yes	Transmission records are summarized in PLM Local transmission records are summarized in Gas Facility Maintenance (Gas FM) program	To record manufacturer specification information, serial numbers, and to document that maintenance work is performed according to maintenance schedules and intervals	Backbone transmission records are located in transmission districts Local transmission records are located in local division offices	Maintenance field and supervisory personnel Valve and Regulator process owner (Integrity Management Department) Operations Specialists Local engineers	In connection with maintenance work and for audit and compliance	In hardcopy format Summary information accessed through PLM and/or Gas FM	Not related
Patrol records	Yes	None	To document patrols of pipelines and the findings	For backbone transmission the patrol records are located in the transmission districts For local transmission the patrol records are located in the local division offices Aerial patrol schedules are maintained in PG&E's Walnut Creek offices	Mappers Maintenance personnel PLEs Integrity Management	To ensure the integrity and safe operation of the pipeline	In hardcopy format	Not related

Record Type	Is Record PG&E's Source Record?	Information in Record Contained in Summary Record/Analytic Tool?	Purpose of Record	Record Location	Typically Accessed By	Typically Accessed For	How Accessed	Relation to GIS
Operator qualification (OQ) records	Yes	Selected fields entered into OQ Database	To record personnel qualification information consistent with regulatory standards in PHMSA Subpart N	Created by OQ evaluator, the original is transmitted to PG&E's San Ramon facility where it is entered into the OQ database and a copy is kept by the local evaluator	Front-line supervisors OQ process owner (Integrity Management Department) Qualified employees PG&E Academy personnel	To ensure the qualification of pipeline personnel and to document regulatory compliance	In hardcopy format and in OQ database	Not related
Records Associated with Integrity Management of Gas Transmission Pipelines[10]								
Documents associated with Risk Management Procedure (RMP) compliance, including: ECDA findings SCDA findings ILI findings Risk committee notes Risk rankings Other pipeline assessment records	Yes (for integrity management purposes)	LTIMP summary	To conduct PG&E's Integrity Management analyses and to promote pipeline safety and integrity	PG&E's Walnut Creek offices	Integrity Management personnel Pipeline engineers	To conduct PG&E's Integrity Management Program To ensure a safe and reliable gas transmission system To provide background information in connection with project development, design and construction	In hardcopy format and electronically on shared drives	Not directly related, however the integrity management process may help to validate data

10 This group of records generally corresponds to "risk assessments" in Legal Division's PHC statement.

Table 2A-3 distinguishes between source records and summary records or analytical tools. For example, job files are the original source records for design and engineering data for gas transmission pipelines. PG&E's Geographic Information System (GIS) is an electronic tool that contains, among other things, design and construction data, including data drawn from job files. The GIS design and construction data are stored in electronic form and can be accessed virtually instantaneously by gas personnel. GIS assists pipeline engineers and other personnel to access pipeline data.[11]

For example in the case of a Pipeline Engineer (PLE) consulting GIS, the tool is a "portal" to some of the underlying source records and information, and can help orient the PLE. The PLE may find all the information he or she needs by consulting GIS, or the PLE may also need to consult job files for additional, or more detailed, design and construction information (for example in connection with performing an In-Line Inspection). In other cases, all the relevant information from paper records (for example, "A" Forms used to record leaks) is input into an electronic system (IGIS), which is accessible system-wide.

However, even in cases where an electronic system is populated with all data from hardcopy files, the hardcopy files remain the source record for most purposes. By source record, PG&E means the record that captures original information. GIS is generally not a source record; it presents data for summary purposes or for use as an analytic tool. There are two primary instances where electronic data systems have emerged as source records: the IRTHNet system, which is used to access USA one-call ticket information, and GIS itself – but only to the limited extent that GIS is used (i) to cal-

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11 One advantage of PG&E's GIS is that it is searchable electronically, allowing gas pipeline information to be efficiently identified, accessed and retrieved by PG&E's pipeline engineers and other personnel regardless of their office location. The gas transmission GIS contains data for pipelines (pipe design characteristics), stations, and main line valves, and also provides links to pipeline operating maps and facility operating diagrams. Over several hundred types of data are tracked in one or more of the layers of GIS. GIS contains information about each of the approximately 20,000 unique pipeline segments that comprise PG&E's gas transmission system.

culate High Consequence Areas (HCAs) (geographic areas) and (ii) to prepare pipeline risk rankings for integrity management purposes.

In cases where job files need to be retrieved, GIS also facilitates that retrieval, because job file numbers are linked in GIS to pipeline segments. Figure 2A-1 is a simplified flowchart that illustrates how GIS can be used for this purpose.

FIGURE 2A-1
PACIFIC GAS AND ELECTRIC COMPANY
ACCESSING JOB FILES ASSOCIATED WITH A PARTICULAR GAS TRANSMISSION PIPELINE SEGMENT

A more detailed schematic of how GIS facilitates job file access and retrieval, and how PG&E manages its recordkeeping and information flow in connection with new gas transmission pipeline projects, can be found in Attachment P2-1457 (Gas T&D Custom Pipeline Design Process Map (Level 3) [Applicable to Capital Projects > $1.0 million]).

Finally, Table 2A-3 provides some detail about PG&E's gas transmission analysis tools, most particularly about GIS. There are several electronic data management tools used by PG&E. IGIS is the enterprise-wide computer system used by PG&E to track leaks and leak information. A Form (leak) information is input into the IGIS system for the purpose of scheduling and tracking leak repairs. IGIS' historical development is described above in Table 2A-2. PLM is the PipeLine Maintenance program. It is used by PG&E's gas transmission group to schedule and track maintenance work on gas transmission pipelines. Gas FM is the Gas Facility Maintenance program. It is used to schedule and track distribution and local transmission pipeline maintenance work. Finally, SAP (a third party software product) is an asset management system utilized by PG&E. Among other things, it issues “tickets” for certain local transmission pipeline maintenance work, and records certain information concerning the maintenance that needs to be performed.

E. Conclusion

As illustrated above in Tables 2A-2 and 2A-3, PG&E’s recordkeeping and retrieval capabilities have significantly evolved over the past 55 years, responding to changing operational needs, engineering judgment, and recordkeeping requirements. PG&E’s current recordkeeping and retrieval systems need to be improved in order to more comprehensively and effectively evaluate the integrity of our gas transmission pipelines, as contemplated by the Integrity Management Requirements in Subpart O. PG&E is committed to this improvement, and has begun to implement an improved GIS system.

TAB 6

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2B

EXPERT REPORT OF EDWARD J. ONDAK

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2B
EXPERT REPORT OF EDWARD J. ONDAK

I, Edward J. Ondak, make the following report in the matter of the California Public Utility Commission's Order Instituting Investigation issued February 24, 2011 (I.11-02-016):

I received a Bachelors of Science degree in Electrical Engineering with a minor in Mathematics from Indiana Institute of Technology in 1964. I am a registered Professional Engineer in California and a certified Corrosion Specialist.

I began my career in the natural gas industry in 1957, when I spent a summer working for East Ohio Gas (now known as Dominion Gas) in Canton, Ohio. My primary duties were to ensure that the pipeline was under cathodic protection. I worked for Northern Indiana Public Service Company (NIPSCO) in the summer of 1958. There, I worked as a junior engineer. I did everything from mapping, to design, to installation.

After graduating from college in March 1964, I was employed by Columbia Gas System as a district corrosion engineer. My primary duties included responsibility for five divisions responsible for maintaining 3,900 miles of distribution pipeline in an 8,000 square mile service territory. In 1970, I was promoted and became the Senior Corrosion engineer. I left the Columbia Gas System in December 1974. At that time, I accepted a position with the Office of Pipeline Safety, U.S. Department of Transportation, as a program manager. In that capacity, my responsibilities included teaching federal safety standards in all states of the United States by putting on seminars and writing courses to teach federal and state pipeline safety inspectors. In 1980, I moved to Kansas City where I was the Central Regional Director. There, I oversaw the safety operations of all of the operators in 12 mid-western states, developed yearly inspection programs, and provided guidance for government engineer inspectors. In 1990, I moved to Denver where I served as OPS' Western Regional Director. My region encompassed eleven western states, including

California. My duties included providing safety oversight and inspection of the Trans Alaska Pipeline system. Following a large replacement of the Trans Alaska Pipeline due to corrosion I worked to ensure that cathodic protection on the pipeline was consistent with pipeline safety regulations.

In 2000, I was promoted to the position of Senior Technical Advisor. This position involved research and development projects for the OPS and required nation-wide travel and meetings with various academic and industry personnel to keep abreast of new and developing technology pertaining to pipelines. In this role, I also worked to develop the Direct Assessment standard for OPS as it pertained to the pending Integrity Management rulemaking. I set up and tested new methodologies and reported back to the Associate Administrator of the OPS. I also worked with the industry to verify results of industry testing to prove the viability of direct assessment methods.

I have extensive experience in pipeline safety training. Beginning in 1974, I was involved in training pipeline safety inspectors at the Department of Transportation's facility in Oklahoma City. At the time that I took on these responsibilities, the facility offered only one course, called "pipeline safety standards." Subsequently, I developed a total of eight courses, including courses in failure investigation, two courses on corrosion (basic and advanced), joining of materials, pressure regulation, and liquefied natural gas. To this day, I continue to teach the corrosion course for the Department of Transportation at its Oklahoma City facility.

I also have extensive experience in auditing and inspecting the gas safety practices of gas transmission operators. I have been involved in hundreds of audits over the course of my career, and I have reviewed the gas pipeline safety records of hundreds of operators.

Since retiring from the Department of Transportation in 2002, I have remained active in the natural gas field by consulting and training on a variety of natural gas transmission and distribution matters in the United States and abroad. I have previously consulted on behalf of numerous gas utility operators, including PG&E. I also have continued to teach a number of courses on natural gas transmission and distribution maintenance, most recently a corrosion control course for operators in China in April 2011, a NACE certification course in

Claysville, Pennsylvania in June 2011, and a corrosion control course for state and federal inspectors in Oklahoma City in June 2011.

During the time that I worked for NIPSCO in the late 1950s and early 1960s, gas transmission records and maps were kept entirely on paper and were largely handwritten. The paper records often took the form of note cards and the maps were maintained on a thin silk paper. Drawings were made by hand in ink. I continued to make extensive use of handwritten, paper safety records during my periods of subsequent employment by the East Ohio Gas Company (now known as Dominion Gas) and the Columbia Gas Company. The position with the Columbia Gas Company involved the oversight of all the cathodic protection of the transmission pipelines operated by the company in the state of Ohio. Included in this position was maintaining the recordkeeping system that was already in place by the company. These records were all in the form of paper records and test station cards depicting the readings taken to ensure the regulation requirements were met. At that time, there were no computers or electronic methods available, so all records were hand written or typed and filed by our secretary.

I agree with a recent statement issued by the American Gas Association: "The natural gas industry is no different from other industries that face a challenge in maintaining its records of assets that are over 40 years old." In the case of the natural gas industry, I see at least seven recordkeeping challenges that transmission operators face today:

(a) First, gas transmission lines are spread across a wide territory. The construction and maintenance of those lines occur not at a single central location, but in countless locations, many of them remote. The work itself is done in the field, not from behind a desk. Crews are dispatched not from a central office but from different division and district offices, each with different supervisors and personnel. Pipeline safety activities generate records, and these records are used for many different purposes: construction, maintenance, operations, corrosion control, and integrity management. Each operator's division or district office posed unique challenges for managing pipeline safety records as each division or district office may have its own manager who determines how and where to keep and maintain records at that particular facility. In my experience, no two operators had the same recordkeeping system and even an individual operator may have different recordkeeping practices within its system. In other words, each division or district set up its own system.

(b) Second, a significant amount of the transmission pipeline in the United States (more than 60%) was installed prior to federal gas pipeline safety regulations taking effect in 1970. Both the Natural Gas Pipeline Safety Act of 1968, and the regulations implementing it in 1970, reflected high-level policy decisions to partially exempt these existing pipelines from regulation insofar as their design, construction, and initial testing were concerned. The impacts for historic recordkeeping practices are obvious. The regulations do not retroactively address how an operator should have designed, constructed, or initially tested a pipeline installed before pipeline safety laws took effect. Therefore, the regulations do not address what records the operator must have retained for those activities. As such, it was very difficult for operators to determine parameters for many of the pipeline systems. Most of the time we used good engineering judgment based on the little information we had and subsequent readings performed on a particular segment.

(c) Third, many operators grew their transmission systems through a combination of mergers and acquisitions of other pipeline operators. When acquiring another company, a gas operator may have received no records at all or records that contain significant gaps.

(d) Fourth, federal pipeline safety rules address recordkeeping on a subject-by-subject basis. The rules do not contain comprehensive recordkeeping standards. What guidance exists says in effect that operators must have records that demonstrate compliance with the regulations, but they do not describe how to comply. For example, 49 C.F.R. § 192.947 states, “Operators must retain, for the useful life of the pipeline, records that demonstrate compliance with this subpart. . . .” I expect we will see more regulatory guidance given to the industry on the subject of recordkeeping in the near future. On May 24, 2011, the Department of Transportation issued a Notice of Public Meetings on Managing Challenges with Pipeline Seam Welds and Improving Pipeline Risk Assessments and Recordkeeping for July 20th and 21st, 2011. DOT wrote that the meetings would address, among other things: "interactive threats, legacy pipelines and approaches for dealing with recordkeeping gaps."

(e) Fifth, in the absence of recordkeeping standards, an operator's recordkeeping procedures have seldom been the focus of PHMSA or state gas pipeline safety audits. OPS/PHMSA trained federal and state inspectors, including inspectors employed by the California Public Utilities Commission, on how to review the records of the gas transmission operators in their respective states as part of their regular audits of operation. This training provided the inspector with an explanation of the intent of the regulation, what an inspector had to look at to ensure compliance with the requirements of the regulations. As to the records deemed necessary to ensure compliance, a checklist was developed for the inspectors to use. The onus was placed on the operator to demonstrate how it met the compliance requirements. I believe this effort helped to improve the quality and consistency of auditing by state inspectors. But based on my experience, the industry has not received a significant amount of feedback or input from federal or state regulators on how they should maintain their records. This is not to say auditors do not review pipeline safety records in the course of their audits – they most certainly do. However their reviews tend to focus on operational records and specific program areas, *e.g.*, Operations, Maintenance and Emergency Plans. They have not – to this point in time at least – focused on whether the operators have adopted the appropriate recordkeeping procedures or whether the operator's records are readily accessible for different uses. Again, the fact that PHMSA is now holding meetings to discuss ways to improve industry recordkeeping practices is evidence of the need within the industry for improved recordkeeping methodologies.

(f) Sixth, the industry has seen dramatic changes over time in terms of how documents and data are stored and managed. In my time in the industry and in DOT, I have seen the industry move from storing records on paper (many operators still do), on microfilm, on main frame computers, on PCs networked to certain divisions or units within the company, and on comprehensive enterprise-wide data management platforms. With each change in data management system that an operator adopts, there is the potential for data to be left behind, rendered unreadable, or misinterpreted. Over time, operators may have reorganized their gas operations or relocated them. Maintaining ready access to source records and summary data across these different changes in data management systems and organizational changes has been an industry-wide challenge. Paper records are durable, but not necessarily readily retrievable for use in all modern gas pipeline safety practices. Electronic records, in contrast, have the potential to greatly enhance the retrievability of gas pipeline records, but at the potential cost of durability when an operator migrates from one system to another. The quality of electronic data migrations depends on how the people involved in the data entry or conversion incorporate the new data, and it depends on business decisions. Each manager has a different perspective on what data is needed to be kept. And, operators cannot always foresee the need to retain certain data in an electronic form because they cannot always foresee how regulations or industry standards may change in the future.

As I reflect back on these challenges, I am reminded of instances of operators who asked the Office of Pipeline Safety (OPS) for guidance when developing procedures to migrate from one data storage medium (paper) to another (computers). Even when specifically asked, OPS generally declined to review the operator's procedures, citing the fact that it did not have generally applicable recordkeeping procedures against which to judge the operator's procedures. See Attachments A and B.

(g) Seventh, the industry is still digesting the impact the 2003 TIMP regulations have had on recordkeeping practices. The introduction of integrity management principles into the pipeline industry changes how pipeline safety records are used. There have long been recordkeeping requirements, including so called "life of the pipeline" requirements. However, pipeline records tend to be used because they are needed for a discrete reason, *e.g.*, a pipeline needs to be relocated and the engineer needs to review as-built documents for that particular pipeline. In that context, the precise storage location of the records (local or central) or the form of the records (paper or electronic) is not critical. Integrity

> Management rules, in contrast, introduce a different way of using records. They introduce standards for gathering and using records on a system-wide basis (not to complete a specific work task). Thus, the ASME standards speak for the first time of the need to gather, review and integrate data and, where data is missing, to make certain conservative assumptions. For operators whose document and information management systems pre-date integrity management practices, the data may have been stored to be retrieved for discrete purposes, but not necessarily for the sort of proactive use contemplated by TIMP.

There has long been a tension in the industry between the records the industry should now possess, and the records the industry in fact possesses. Let me provide an example. I was the sole governmental representative on a Committee that helped draft the External Corrosion Direct Assessment (ECDA) standards in early 2000s. When discussing the pre-assessment phase for ECDA, the Committee took into account the kinds of records and information that an operator should have. I stated the belief during our deliberations that it should be easy for an operator to know what was going on with the pipe because the industry has been maintaining the records. The industry representatives on the committee cautioned me that that was not necessarily the case. In the end, the pre-assessment standard that we wrote struck a balance between a regulatory expectation about the records operators should possess, and the reality of what the industry in fact possessed. This experience was consistent with my other experiences. I can remember several instances when auditing an operator where I asked for a record that I believed the operator should have, only to learn that the record could not be located or that it could be located but only after a significant delay in retrieving it.

There is as yet no industry standard for how to gather and integrate records for integrity management. Many within the industry, PG&E among them, have promoted the use of GIS as a system to store information used in integrity management. There have been industry discussions about what kind of data should be maintained in GIS to support integrity management programs. However, as yet, the industry is still trying to develop a consensus on the kind of data that should be included in an operator's GIS system.

I have reviewed the maximum allowable operating pressure (MAOP) validation reports and supplements/updates from Pacific Gas and Electric Company (PG&E), dated March 15, March 21, May 10, 2011, and June 10, 2011, as well as the MAOP validation report and supplements/updates submitted by the Southern California Gas Company and San Diego Gas & Electric Company (collectively "Sempra") on April 15, 2011, April 19, 2011, April 26, 2011, and May 9, 2011. Based upon this review, and my general understanding of each utility's transmission system, the percentage of pre-1970 pipeline with less than 100% complete records is consistent with my expectations for operators like PG&E and Sempra. I would expect a significant number of pipelines to have never been pressure tested, and I would expect utilities like PG&E to have recordkeeping gaps. If recordkeeping errors or gaps were unique to PG&E, then the NTSB would not have issued its January 3, 2011 Safety Recommendations to PHMSA, and PHMSA would not have issued its industry-wide Advisory Bulletin earlier this year. It is unrealistic to expect that an operator will be able to establish a perfect chain of custody for pipeline safety records, especially for pipelines installed more than 40 or 50 years ago.

In my many years of service with the Department of Transportation and particularly as its Western Region Chief, it was my experience that PG&E, along with other operators in the country, participated actively in the industry's efforts to promote safety on gas transmission pipelines. The activities I am familiar with include PG&E's leadership roles in organizations such as the Gas Research Institute, API, ASME and NACE as well as development of the current Transmission Integrity Management Program regulations.

The natural gas transmission industry did not begin the process of transitioning to a risk management model for assessing and maintaining pipeline integrity until the 1990s. During the mid-1990s, a highly influential and widely read book among state and federal regulators and the industry was W. Kent Muhlbauer's Pipeline Risk Management Manual, first published in 1992. That book started discussions within the industry that lead to the formation of Quality Action Teams in 1994. In 1996, Congress' Accountable Pipeline Safety and Partnership Act of 1996 required the Office of Pipeline Safety to develop a Pipeline Risk Management Demonstration Plan. That plan was designed to test whether a structured and formalized process for identifying pipeline-specific risks, allocating resources to the most effective risk control activities, and monitoring safety and environmental performance could lead to superior safety and environmental protection, providing for a greater level of public participation in the regulatory process, a more informed and effective regulator, and increased efficiency and reliability of pipeline operations. In 1999, OPS submitted a Demonstration Project Report to Congress, which helped inform legislative efforts that culminated in the formation of an Integrity Management regulation known as "IMP." The Office of Pipeline Safety issued this Transmission Integrity Management Plan in December 2003, effective 2004.

As a former government pipeline safety regulator involved in developing TIMP standards and rules, I can say that those involved in that process understood that developing a TIMP program would be a continuing process. All of us understood that TIMP was a new rule, that the industry and regulators would learn from experience and improve the TIMP program as it matured. We, as regulators, were learning then about integrity management (and continue to learn) from the experience of operators. Risk management is a dynamic program with built-in features for evaluating and improving safety activities as experience is gained.

In summary, PG&E's recordkeeping challenges, as described in its MAOP validation reports, are similar in nature to what I witnessed in my career with OPS/PHMSA. My experience has been that most operators throughout the United States were and are attempting to do a good job. As I have pointed out, there are no comprehensive recordkeeping guidelines, and it has been up to the discretion of each individual operating company to determine its own recordkeeping system. It is only fair to state that some operating companies do a better job than other companies, but that is subjective. What I find interesting is that each inspector determines what he/she would require from each operator to ensure compliance. I find it even more interesting that very few operators have to this point been provided a written notice of probable violation pertaining to a lack of records, incomplete or insufficient records. I am aware, however, that there have been letters of request sent to operators requesting further elaboration on their system to determine compliance.

I am also aware that on June 9, 2011 a report issued, "Report of the Independent Review Panel: San Bruno Explosion Report of the Independent

Review Panel: San Bruno Explosion." At the present time I have not had the opportunity to fully review this report, and thus do not comment upon it.

ATTACHMENT A

Attachment A is available on the OPS PHMSA website at:

http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=a4173ec78f95b110VgnVCM1000009ed07898RCRD

April 6, 1992

Mr. W. N. Hall
Associate Petroleum Engineer
Dome Pipeline Corporation
Plaza Center One
P.O. Box 1430
Iowa City, IA 52244-1430

Dear Mr. Hall:

This is in response to your letter of November 7, 1991, concerning the recordkeeping requirements of §195.404(c)(3). The letter asks whether magnetic media (computer hard drive or diskettes) may be used in place of hard copies to record and maintain the required records.

Section 194.404(c)(3) requires that each operator maintain a record of each inspection and test required by Subpart F. Records must be maintained for at least 2 years or until the next inspection or test is performed, whichever is longer. Section 195.404(c((3) does not prohibit operators from maintaining the required records on magnetic media. Also, original hard-copy (paper) records need not be retained after their conversion to magnetic media. However, like the original hard copy records, magnetic media records must contain sufficient information to comply with the recordkeeping requirements of §195.404(c)(3).

We trust that this adequately responds to your request. We are sorry we were not able to answer your letter sooner. However, please let us know if we can be of further assistance.

Sincerely,

/signed/

Cesar De Leon
Director, Regulatory Programs
Office of Pipeline Safety

ATTACHMENT B

Attachment B is available on the OPS PHMSA website at:

http://phmsa.dot.gov/portal/site/PHMSA/menuitem.ebdc7a8a7e39f2e55cf2031050248a0c/?vgnextoid=6b6111a0f8f6b110VgnVCM1000009ed07898RCRD&vgnextchannel=9574d7dcb2588110VgnVCM1000009ed07898RCRD&vgnextfmt=print

8-5-93

Mr. Albert T. Richardson
Tenneco Gas
1010 Milam Street
Houston, TX 77252-2511

Dear Mr. Richardson:

This responds to your letter of February 25, 1991, to William Gute. The letter discusses Tenneco's use of computers instead of paper to record and store information it must maintain under 49 CFR Parts 191 and 192. You asked us to determine standards that would be acceptable in maintaining this information in computers.

Under Parts 191 and 192, operators may use any recordkeeping procedure that produces authentic records, without the prior approval of this agency. The proposed standards enclosed with your letter, which are aimed at ensuring the authenticity of computerized records, are permissible under Parts 191 and 192.

Although authenticity of records concerns us, for both computer and paper records, we do not believe there is sufficient need to adopt generally applicable standards governing recordkeeping procedures. In the absence of such standards, we ordinarily do not review an operator's recordkeeping procedures unless the legitimacy of records is in question. Accordingly, we have no comments at this time on the adequacy of your proposed standards.

Sincerely,

George W. Tenley, Jr.
Associate Administrator for
Pipeline Safety

TAB 7

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

DISCUSSION OF SPECIFIED NTSB REPORTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
DISCUSSION OF SPECIFIED NTSB REPORTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
DISCUSSION OF SPECIFIED NTSB REPORTS

A. Introduction

In OII Directive 1, the Commission directs PG&E to "[l]ist each factual contention stated, and conclusion reached, by the NTSB reports (Appendix A, B, C) that PG&E contends is incorrect, and provide support for PG&E's position." OII at 17. Appendices A, B, and C are, respectively: (A) NTSB Preliminary Report, issued October 13, 2010; (B) NTSB Safety Recommendations P-10-1 through P-10-7, issued January 3, 2011; and (C) NTSB Materials Laboratory Factual Report, report No. 10-119, dated January 21, 2011.

This OII is currently focused on PG&E's records and recordkeeping practices and policies. As stated in its prehearing conference statement, PG&E understands OII Directive 1 to "call for PG&E to respond to the NTSB 'findings' with respect to PG&E's gas pipeline records…." *See* PG&E's Prehearing Conference Statement, filed March 15, 2011, at 3. Consistent with the scope of this records OII, PG&E responds to Directive 1 by identifying those "factual contentions" in the specified NTSB reports that are related to records and recordkeeping and are incorrect, incomplete or otherwise inaccurate.

PG&E responds to each of the NTSB documents specified by the Commission in the following sections.

B. Discussion

PG&E appreciates the opportunity to address the factual determinations the NTSB has made and that the NTSB will make at the conclusion of its investigation. At this time, the NTSB has not completed its investigation and has not issued its final report or reports, which will contain the NTSB's final factual determinations and conclusions, in particular with respect to the probable root cause and contributing causes. Until the NTSB issues those final determinations, a comprehensive discussion of the correctness of the NTSB's factual contentions and conclusions is not only beyond the current focus of this proceeding, it is premature.

1. NTSB Preliminary Report, Dated October 13, 2011

The October 13, 2010 Preliminary Report contains no factual contentions related to PG&E's records and/or recordkeeping practices and policies.[1]

Given its timing in relation to the San Bruno tragedy, the October 13, 2010 Preliminary Report is necessarily summary in nature and limited in its detail. Subsequently, on March 1, 2011, the NTSB publicly disclosed its Operations Group Chairman Factual Report. *See* Operations Group Chairman Factual Report, dated February 10, 2011, NTSB Docket No. SA-534, Ex. 2-A (hereinafter *Operations Group Report*). The Operations Group Report provides significant additional information and detail regarding the San Bruno tragedy. At the end of August or beginning of September 2011, PG&E expects the NTSB will issue its final report addressing the Line 132 rupture, which will include the NTSB's final statements regarding the pertinent facts, as well as the NTSB's probable root cause determination. To the extent the NTSB's final report addresses PG&E's records and recordkeeping, PG&E will be able to provide at that time a comprehensive and detailed response to the NTSB's factual statements and conclusions related to PG&E's records and recordkeeping practices and policies.

2. NTSB Safety Recommendations P-10-1 Through P-10-7

On January 3, 2011, the NTSB issued Safety Recommendations P-10-1 through P-10-7 (hereinafter *Safety Recommendations*). PG&E does not know whether the NTSB considers the statements in the Safety Recommendations to be "factual" statements of record in its investigation.

In addition, much of the content of the Safety Recommendations relates to NTSB recommendations to entities other than PG&E; the NTSB's interpretation of regulations and laws; or the NTSB's views, assumptions or opinion on factual or legal matters including the implications to be drawn from the GIS records discrepancy identified by the NTSB. With respect to

[1] In so responding, PG&E does not concede that the factual statements in the October 13, 2010 Preliminary Report are correct, accurate, or complete. However, none of those factual statements are related to PG&E's records and/or recordkeeping practices and policies.

such content, PG&E does not believe it is appropriate to respond or comment while the NTSB's investigation continues.

Having said that, PG&E acknowledges that the Safety Recommendations derive from the record discrepancy identified by the NTSB, and discussed further in Chapter 5. As such, the Safety Recommendations are within the scope of the records OII. In accordance with OII Directive 1, PG&E responds below to the statements in the Safety Recommendations that are clearly NSTB factual statements regarding PG&E's records and recordkeeping policies and practices.

<u>Statement 1</u>: According to PG&E <u>as-built drawings</u> and alignment sheets, <u>Line 132</u>, . . . was constructed using <u>30-inch-diameter seamless steel pipe</u>. . . ." Safety Recommendations at 1.

<u>Response</u>: The statement regarding PG&E's "as-built drawings" is inaccurate. The job file documents for Segment 180 indicate, correctly, that Segment 180 was constructed using 30-inch double submerged arc welded (DSAW) pipe. *See, e.g.,* Pipe Order and Receipt Forms (Attachment #1, PG&E Response to OII Paragraph 1 ("P1-1")); PG&E 1967 Material Code List (P1-2). As discussed in Chapter 5, a Pipeline Survey Sheet created years later incorrectly stated that Segment 180 was constructed with 30" seamless pipe, an error that was carried over to PG&E's Geographical Information System ("GIS").

<u>Statement 2</u>: "The NTSB's examination of the ruptured pipe segment and review of PG&E's records revealed that although <u>the as-built drawings</u> and alignment sheets <u>mark the pipe as seamless</u> API 5L <u>Grade X42</u> pipe, the pipeline in the area of the rupture was constructed with longitudinal seam-welded pipe." Safety Recommendations at 1-2.

<u>Response</u>: See Response No. 1, above. In addition, the material codes contained in the job file documents identify the pipe as Grade X-52, not X-42, pipe. *See* PG&E 1967 Material Code List (P1-2).

3. NTSB Materials Laboratory Factual Report, Report No. 10-119, Dated January 21, 2011

The January 21, 2011 NTSB Materials Laboratory Factual Report (hereinafter *January 2011 Metallurgy Report*) does not relate to the subject matter of this OII, namely, PG&E's records and recordkeeping. The January

2011 Metallurgy Report details the testing and investigation of the ruptured pipe section (and adjacent pipe sections) involved in the San Bruno accident. PG&E's records and recordkeeping practices and policies are not addressed in this report. There are no NTSB "factual contention[s] stated, and conclusion[s] reached," in the January 2011 Metallurgy Report that are within the scope of the OII.

Moreover, as with the October 13, 2010 Preliminary Report, the NTSB has issued a subsequent metallurgy report supplementing the January 2011 Metallurgy Report. *See* Metallurgy Group Chairman Factual Report, Materials Laboratory Factual Report, report No. 11-005, dated February 9, 2011, NTSB Docket No. SA-534, Ex. 3-B. PG&E also anticipates that the NTSB will release with its final report(s) an update or further supplement to its prior metallurgy reports. To the extent a final metallurgy report is relevant to this records OII, PG&E welcomes the future opportunity to respond in detail to the relevant content in that report.

TAB 8

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3A

SUPPLEMENTAL DISCUSSION OF SPECIFIED NTSB REPORTS

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SUPPLEMENTAL DISCUSSION OF SPECIFIED NTSB REPORTS

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CHAPTER 3A
SUPPLEMENTAL DISCUSSION OF SPECIFIED NTSB REPORTS

A. Introduction

In OII Directive 1, the Commission directs PG&E to "[l]ist each factual contention stated, and conclusion reached, by the NTSB reports (Appendix A, B, C) that PG&E contends is incorrect, and provide support for PG&E's position." OII at 17. Appendices A, B, and C are, respectively: (A) NTSB Preliminary Report, issued October 13, 2010; (B) NTSB Safety Recommendations P-10-1 through P-10-7, issued January 3, 2011; and (C) NTSB Materials Laboratory Factual Report, report No. 10-119, dated January 21, 2011.

PG&E responded to Directive 1 on April 18, 2011 by identifying those "factual contentions" in the specified NTSB reports that are related to records and recordkeeping and are incorrect, incomplete or otherwise inaccurate. At the Prehearing Conference on May 9, 2011, the Administrative Law Judge asked PG&E to supplement its response to list all factual contentions, not just those related to records and recordkeeping. PG&E provides the following supplemental response.

B. Discussion

The NTSB still has not completed its investigation and has not issued its final report or reports, which will contain the NTSB's final factual determinations and conclusions with respect to probable root and contributing causes. Until the NTSB issues those final determinations, PG&E has limited ability to discuss comprehensively the correctness of the NTSB's preliminary factual contentions and conclusions.

1. NTSB Preliminary Report, Dated October 13, 2011

As noted in PG&E"s April 18, 2011 filing, the October 13, 2010 Preliminary Report is summary in nature and limited in its detail. On March 1, 2011, the NTSB publicly disclosed its Operations Group Chairman Factual Report. *See* Operations Group Chairman Factual Report, dated February 10, 2011, NTSB Docket No. SA-534, Ex. 2-A (hereinafter *Operations Group Report*). At the end of August or beginning of September

2011, PG&E expects the NTSB will issue its final report(s) addressing the Line 132 rupture.

Pursuant to OII Directive 1 and the ALJ's instruction at the Prehearing Conference, PG&E identifies the following factual contentions that are incorrect or inaccurate as stated in the October 13, 2010 Preliminary Report. (Italics indicate specific inaccuracies, where appropriate.)

<u>Statement 1:</u> "*Type of System: 30-inch* natural gas transmission pipeline." October 13 Preliminary Report at 1.

<u>Response</u>: This statement is incomplete and inaccurate. Segment 180 of Line 132 is constructed of 30" pipe. However, Segment 180 is a 1742 foot long section of Line 132. Line 132 is approximately 50 miles long, is interconnected with Lines 101 and 109 at multiple cross-tie locations, and is comprised of pipe of multiple diameters, including 24", 30", 34" and 36". Pipeline Survey Sheets, Line 132, (P1-8).

<u>Statement 2:</u> "On September 9, 2010, at approximately 6:11 pm Pacific Daylight Time, *a 30-inch diameter natural gas transmission pipeline (Line 132)*. . ." October 13 Preliminary Report at 1.

<u>Response</u>: See Response No. 1, above.

<u>Statement 3:</u> "According to PG&E records, *Line 132*, ... was constructed using *30-inch diameter steel pipe*. . . ." October 13 Preliminary Report at 1.

<u>Response</u>: See Response No. 1, above.

<u>Statement 4:</u> "Just before the accident, PG&E was working on their uninterruptible power supply (UPS) system at Milpitas Terminal, which is located about 39.33 miles southeast of the accident site. During the course of this work, *the power supply from the UPS to the supervisory control and data acquisition (SCADA) system malfunctioned* so that instead of supplying a predetermined output of 24 volts of direct current (VDC), the UPS system supplied about 7 VDC or less *to the SCADA system.*_ Because of this anomaly, *the electronic signal to the regulating valve for Line 132 was lost. The loss of the electronic signal resulted in the regulating valve moving from partially open to the full open position as designed.* The pressure then *increased to 386 psig.* The *over-protection valve*, which was pneumatically

activated and did not require electronic input, *maintained the pressure at 386 psig*." October 13 Preliminary Report at 1-2.

<u>Preface</u>: This paragraph contains several inaccurate statements, and is a substantially incomplete description of the events related to Milpitas Station. The NTSB Operations Group Report clarified many of these inaccurate statements and provided a more comprehensive description of these events. Below PG&E identifies the inaccurate and incomplete statements in the Preliminary Report.

<u>Response</u>:

- The second sentence is inaccurate and incomplete. The power failure related to two 24 VDC power supplies (PS-A and PS-B), not the UPS. These power supplies provided power to pressure reading transmitters at Milpitas Station, not to the SCADA system. Interview of SCADA Controls Group Supervising Engineer, Docket No. SA-534, NTSB Ex. 2-V, (P1-3); Milpitas Terminal One-Line Diagram, Docket No. SA-534, NTSB Ex. 2-G, (P1-6).
- The third and fourth sentences are inaccurate and incomplete. The loss of power was to pressure reading transmitters, not the regulating valves. This loss of power to the pressure reading transmitters was interpreted by the regulating valves as 0 psig of gas in the lines, which caused the regulating valves to move to the fully open position, as they were designed to do. Interview of SCADA Controls Group Supervising Engineer, Docket No. SA-534, NTSB Ex. 2-V, (P1-3); Milpitas Terminal One-Line Diagram, Docket No. SA-534, NTSB Ex. 2-G, (P1-6).
- The fifth sentence is inaccurate and incomplete. Pressure readings from September 9, 2010 indicate that pressure increased to 392 psig prior to being reduced and controlled by the monitor valves at 386 psig. SCADA Pressure Readings on September 9, 2010, Docket No. SA-534, NTSB Ex. 2-K, (P1-7).
- The sixth sentence is inaccurate and incomplete. The monitor valves, not "over-protection valves", returned the pressure to 386 psig when automatically activated in response to the pressure increase. Interview of SCADA Controls Group Supervising Engineer,

Docket No. SA-534, NTSB Ex. 2-V, (P1-3); SCADA Pressure Readings on September 9, 2010, Docket No. SA-534, NTSB Ex. 2-K, (P1-7).

Statement 5: "The SCADA system indicated that the pressure at Martin Station continued to increase until it *reached about 390 psig at about 6:00 p.m.* At 6:08 p.m., *it dropped to 386 psig*." October 13 Preliminary Report at 2.

Response: This statement is inaccurate. The pressure at Martin Station never reached 390 psig. The highest pressure at Martin Station was 386 psig, which occurred at 6:08 p.m. The pressure did not "drop" to 386 psig. SCADA Pressure Readings on September 9, 2010, Docket No. SA-534, NTSB Ex. 2-K, (P1-7).

Statement 6: "PG&E *dispatched a crew at 6:45 p.m.* to isolate the ruptured pipe section by closing the nearest mainline valves. October 13 Preliminary Report at 2.

Response: This statement is incomplete and inaccurate. Concord Dispatch dispatched a PG&E Gas Service Representative to the scene at 6:23 p.m. He was on-scene by 6:41 p.m. Several off-duty PG&E personnel called Concord Dispatch as early as 6:18 p.m. to report the fire and notify PG&E that they were headed to the site. At least one was on-scene at 6:41 p.m. At 6:35 p.m., a PG&E T&R mechanic notified Concord Dispatch that he was on his way to the Colma Yard to retrieve his truck and equipment and respond to the site. At 6:40 p.m., the PG&E on-call supervisor contacted this T&R mechanic to dispatch him to the Colma Yard; the mechanic already was on his way to the yard. PG&E Event Timeline, Docket No. SA-534, NTSB Ex. 2-B, (P1-4); NTSB Incident Timeline, Docket No. SA-534, NTSB Ex. 2-B, (P1-5).

Statement 7: "The upstream valve (MP 38.49) was *closed at about 7:20 p.m.* and the downstream *valve* at Healey Station (MP 40.05) was *closed at about 7:40 p.m.*" October 13 Preliminary Report at 2.

Response: This statement is inaccurate and incomplete. PG&E T&R mechanics arrived at the upstream valve (MP 38.49) at 7:20 p.m. The valve was closed at 7:30 p.m. Two valves were closed at Healey Station (MP 40.05). They were closed at 7:45 p.m. PG&E Event Timeline, Docket No.

SA-534, NTSB Ex. 2-B, (P1-4); NTSB Incident Timeline, Docket No. SA-534, NTSB Ex. 2-B, (P1-5).

2. NTSB Safety Recommendations P-10-1 Through P-10-7

On January 3, 2011, the NTSB issued Safety Recommendations P-10-1 through P-10-7 (hereinafter *Safety Recommendations*).[1] As stated in its April 18th submission, PG&E does not know whether the NTSB considers the statements in the Safety Recommendations to be "factual" statements of record in its investigation. However, in accordance with OII Directive 1 and the ALJ's subsequent direction, PG&E responds below to the statements in the Safety Recommendations that are NSTB factual statements or that could be construed as factual statements or conclusions by the NTSB. (Italics indicate specific inaccuracies, where appropriate.)

Statement 1: "On September 9, 2010, at approximately 6:11 pm Pacific Daylight Time, *a 30-inch diameter natural gas transmission pipeline (Line 132)*....." Safety Recommendations at 1.

Response: This statement is incomplete and inaccurate. Segment 180 of Line 132 is constructed of 30" pipe. However, Segment 180 is a 1742 foot long section of Line 132. Line 132 is approximately 50 miles long, is interconnected with Lines 101 and 109 at multiple cross-tie locations, and is comprised of pipe of multiple diameters, including 24", 30", 34" and 36". Pipeline Survey Sheets, Line 132, (P1-8).

Statement 2: According to PG&E *as-built drawings* and alignment sheets, *Line 132*, . . . was constructed using *30-inch-diameter seamless steel pipe*. . . ." Safety Recommendations at 1.

Response: The statement regarding PG&E's "as-built drawings" is inaccurate. The job file documents for Segment 180 indicate, correctly, that Segment 180 was constructed using 30-inch double submerged arc welded (DSAW) pipe. *See, e.g.,* Pipe Order and Receipt Forms (Attachment #1, PG&E Response to OII Paragraph 1 ("P1-1")); PG&E 1967 Material Code List (P1-2). As discussed in Chapter 5, a Pipeline Survey Sheet created years after the Segment 180 relocation project incorrectly stated that

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1 The NTSB directed Safety Recommendations P-10-2, P-10-3 and P-10-4 to PG&E; Safety Recommendation P-10-1 to PHMSA; and Safety Recommendations P-10-5, P-10-6 and P-10-7 to the Commission.

Segment 180 was constructed with 30" seamless pipe, an error that appears to have carried over to PG&E's Geographical Information System ("GIS") when GIS was initially populated with data in the 1990s.

Statement 3: "The NTSB's examination of the ruptured pipe segment and review of PG&E's records revealed that although *the as-built drawings* and alignment sheets *mark the pipe as seamless* API 5L Grade X42 pipe, the pipeline in the area of the rupture was constructed with longitudinal seam-welded pipe." Safety Recommendations at 1-2.

Response: See Response No. 2, above. In addition, the material codes contained in the job file documents identify the pipe as Grade X-52, not X-42, pipe. *See* P1-2.

Statement 4: "PG&E's *records identify Consolidated Western* Steel Corporation *as the* manufacturer *of the accident segment* of Line 132." Safety Recommendations at 2, Footnote 2.

Response: PG&E's records identify Consolidated Western as the manufacturer of the pipe with which Line 132 was constructed in 1948. PG&E's post-rupture investigation suggests that the 1956 relocation of a portion of Line 132, which includes the accident segment of Line 132, was constructed using 30 inch pipe manufactured by Consolidated Western that was purchased but not used in connection with jobs in 1948 (Line 132), 1949 (Line 153) or 1953 (Line 131). See NTSB Data Response NTSB_036-015A (January 13, 2011), Docket No. SA-534, Ex. 2-AF (P3-30008).

Statement 5: "It is critical *to know all the characteristics of a pipeline in order to establish a valid MAOP* below which the pipeline can be safely operated." Safety Recommendations at 2.

Response: Under 49 CFR §192.619(c), a valid MAOP may be established for existing pipelines by the highest operating pressure between July 1, 1965 and July 1, 1970. It is not correct to state that a *valid* MAOP can only be determined based on pipeline specifications. Additionally, where specific information is unknown, the code provides that conservative assumptions can be used in establishing an MAOP. See 49 CFR §192.107(b).

Statement 6: "The NTSB *is concerned* that *these inaccurate* records may lead to incorrect MAOPs." Safety Recommendations at 2.

<u>Response</u>: The NTSB's "concern" is not a statement of fact. Also, the statement assumes the existence of "these inaccurate records" when no specific records or inaccuracies have been identified (apart from the "seamless" discrepancy previously addressed in the Safety Recommendations). The regulations, 49 CFR §192.619(c), authorize establishing MAOP based on historic operating pressure. Such a pressure cannot be said to be "incorrect."

<u>Statement 7:</u> "It is *advantageous to include a spike test* because it limits the time the line is at the higher pressure to reduce the potential amount of crack growth." Safety Recommendations at 2.

<u>Response</u>: This statement is the NTSB's view regarding the benefits and practicalities of different pressure test methods and is not a statement of fact.

<u>Statement 8:</u> "Consequently*, it is preferable to use available design, construction, inspection, testing, and other related records to calculate the valid MAOP*." Safety Recommendations at 2.

<u>Response</u>: This statement is the NTSB's view regarding methods of establishing MAOP. As noted in Response No. 6 above, a "valid MAOP" can be established pursuant to 49 CFR 192.619(c). Nonetheless, as previously stated PG&E supports eliminating this method of establishing MAOP under the regulations.

3. NTSB Materials Laboratory Factual Report, Report No. 10-119, Dated January 21, 2011

The January 21, 2011 NTSB Materials Laboratory Factual Report (hereinafter *January 2011 Metallurgy Report*) details the testing and investigation of the ruptured pipe section (and adjacent pipe sections) involved in the Line 132 accident. As with the October 13, 2010 Preliminary Report, the NTSB has issued subsequent metallurgy reports supplementing the January 2011 Metallurgy Report. *See* Metallurgy Group Chairman Factual Report, Materials Laboratory Factual Report, report No. 11-005, dated February 9, 2011, NTSB Docket No. SA-534, Ex. 3-B. PG&E also anticipates that the NTSB will release with its final report(s) an update or further supplement to its prior metallurgy reports.

For purposes here, PG&E responds as follows. PG&E is a member of the Metallurgical Group formed by the NTSB in connection with its investigation. However, PG&E has not directed, conducted or observed all the metallurgical testing conducted by the NTSB and does not have direct knowledge regarding the conduct of the testing itself. PG&E's knowledge with respect to the results of the metallurgical testing is limited to the results as reported by the NTSB. Accordingly, PG&E cannot comment on the integrity of the testing conducted or the validity and accuracy of the results reported in the January 2011 Metallurgy Report (or any other metallurgical reports the NTSB has issued or will issue). Moreover, the NTSB has not disclosed any conclusions regarding the probable cause or causes of the Line 132 rupture based on the January 2011 Metallurgy Report, thus PG&E cannot comment at this time on any ultimate metallurgical conclusions the NTSB may reach. PG&E has requested additional metallurgical testing that the NTSB has not done.

For purposes of this response, PG&E currently has no reason to dispute the integrity of the metallurgical testing methodologies utilized by the NTSB or the validity and accuracy of the reported results. Therefore, PG&E does not identify any "factual contention stated, and conclusion reached" in the January 2011 Metallurgy Report as incorrect or inaccurate.

TAB 9

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

THE RECORD DISCREPANCY DID NOT IMPACT PG&E'S RISK MANAGEMENT TREATMENT OF SEGMENT 180 OR LINE 132 AND, THUS, DID NOT MAKE THE SAN BRUNO PIPELINE RUPTURE PREVENTABLE

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A. Introduction and Scope

In OII Directive 5, the Commission poses the following question: "Does PG&E contend that the September 9, 2010 San Bruno pipeline rupture was unpreventable by the exercise of prudent utility safety care?" OII at 19. Investigating that broad question may (after the NTSB issues its report(s)) be included in the scope of this proceeding. 3/17/2011 R.T. 11:28-12:8. But at this point it is premature.

Nonetheless, PG&E believes it can respond now with respect to the record discrepancy that is the subject of Directive 6. That is, PG&E's Geographical Information System (GIS) identified the pipe in Segment 180 as seamless instead of longitudinally welded. To determine whether the San Bruno rupture was unpreventable regardless of the record discrepancy, one needS to evaluate whether the record discrepancy impacted PG&E's risk management treatment of Segment 180. So framed, the question becomes whether the correct seam type information in GIS would have changed PG&E's assessment methodology to one focused on long seam threats that may have detected the long seam defect in Segment 180 and potentially prevented the September 9, 2010 San Bruno pipeline rupture. The short answer to that question is "no."

1. The GIS Record Discrepancy

PG&E's GIS database described the pipe in Segment 180 of Line 132 as "seamless." In fact, the pipe in Segment 180 was longitudinally welded. As the NTSB has stated, and PG&E does not dispute, the seam type information in PG&E's GIS database was incorrect with respect to Segment

180.[1] *See* Chapter 5 (PG&E's Response to OII Directive 6) for a discussion of how the error in GIS likely came into existence.

2. The Record Discrepancy Did Not Impact PG&E's Risk Management Treatment of Segment 180 or Line 132

Segment 180 on Line 132 was relocated in 1956 to facilitate new residential development in San Bruno. *See* Job Document (P5-2). Project documents show that the construction called for 30" O.D. x .375" wt DSAW steel pipe. *See* Pipe Order and Receipt Forms (P5-3). DSAW, or Double Submerged Arc Welded pipe, has a longitudinal seam that is welded from both the outside and the inside of the pipe. The NTSB has confirmed that the exposed pipe remaining in the ground at the rupture location on Segment 180 is DSAW pipe.[2] *See, e.g.,* NTSB Materials Laboratory Report, report No. 10-119, dated January 21, 2011, NTSB Docket No. SA-534, Ex. 3-A, at ¶ 3, 62, & 70.

PG&E's research suggests that the pipe used on Segment 180 was pipe remaining from one or more of three earlier purchase orders of 30" pipe from Consolidated Western Pipe: 1948 (~100,000 ft for Line 132); 1949 (~100,000 ft for Line 153); and 1953 (~37,000 ft for Line 131). *See* Potential Sources of Segment 180 Pipe (P5-4). A Moody Engineering Mill Inspection Report for the pipe purchased in 1949 described the welding of the long seam as follows:

> "The cylinders are then progressed through the Berkley Welding Units, where the longitudinal seam is automatically welded on the outside by the "Unionmelt" Electric Fusion method. A similar "Unionmelt" weld is also made along this seam on the inside by the Inside Welding Units. Each of these welds is regulated to penetrate to a minimum of 2/3 of the plate thickness from each side, thereby resulting in an overlap,

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[1] Generally, the pipe specification information in GIS related to Segment 180 and Line 132 as a whole was accurate. *See*, e.g., Pipeline Survey Sheet (Attachment #1, PG&E Response to OII Paragraph 5 ("P5-1")).

[2] The NTSB also has confirmed that the "pups" in the pipe section that failed contain longitudinal seams, but it has not issued a conclusion regarding the type or types of those welds. *See* NTSB Materials Laboratory Report, report No. 10-119, dated January 21, 2011, NTSB Docket No. SA-534, Ex. 3-A, at ¶ 6, 11-13, & 63-69.

> or tie, of these two welds in the middle third of the wall thickness of the cylinder."

Moody Mill Inspection Report (P5-5).

Consistent with both the federal regulations (49 CFR 192 Subpart O) and ASME B31.8, PG&E's risk management program assigns DSAW pipe the highest "joint efficiency factor" of 1 with respect to long seam threats. *See* 49 CFR § 192.113; *see, e.g.,* PG&E RMP-05 at 6 (P5-6); PG&E RMP-06 at 28 (P5-7). When applied in the regulatory design formula for steel pipe, or a relative risk management algorithm for integrity management purposes, the treatment of DSAW pipe is identical to that of seamless pipe of the same wall thickness and yield strength. *See* 49 CFR §§ 192.105 & 192.113.[3]

PG&E's integrity management program is designed to assess for threats that are anticipated to potentially materialize. *See, e.g.,* PG&E RMP-6 at ¶ 17-19, 26-29 (P5-7). Prior to the accident in San Bruno, there was no indication within the industry to suggest that DSAW pipe would present a long seam threat necessitating a long seam assessment.[4] *See* 49 CFR 192.113, 192.917(e). (In light of the San Bruno tragedy, PG&E is taking any new information into account and continues to evaluate its integrity management program to ensure that all potential pipeline threats are most effectively assessed.)

As a result, had GIS identified the pipe in Segment 180 as being DSAW, instead of seamless, it would not have changed the integrity management assessment methodology PG&E determined was most appropriate. PG&E twice used Direct Assessment methodologies because internal or external corrosion and stress corrosion cracking were threats that reasonably could be expected to exist on Line 132. Even had GIS stated that Segment 180 contained DSAW pipe that would not have led to the conclusion that the use

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3 The federal regulations do not distinguish between DSAW and SSAW (Single Submerged Arc Welded) pipe for purposes of joint efficiency factors and long seam threats. Both are assigned a joint efficiency factor of 1 under the category of "Submerged arc welded" pipe. *See* 49 CFR 192.113.

4 Nor had there been a prior long seam leak on Segment 180.

of a long seam threat assessment tool, instead of or in addition to Direct Assessment, was either necessary or warranted.[5]

Thus, that GIS described the ruptured pipe section as "seamless" did not affect the risk management analysis or assessment methodology on Segment 180 or Line 132. The correct DSAW seam designation in GIS would not have changed PG&E's assessment methodology to one focused on long seam threats that may have detected the long seam defect in Segment 180 and potentially prevented the September 9, 2010 San Bruno pipeline rupture.

[5] In fact, GIS and the Pipeline Survey Sheet also erroneously identified the pipe in Segment 180 as having a yield strength of X-42, or 42,000 psi; the material codes in the Segment 180 job file reflect X-52, or 52,000 psi, pipe. Had GIS contained the yield strength indicated by the material codes, the safety margin in Segment 180 would have been considered to be even higher given the more than 20% higher yield strength of X-52 pipe.

TAB 10

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

THE "SEAMLESS" DESIGNATION FOR SEGMENT 180 IN PG&E'S GEOGRAPHICAL INFORMATION SYSTEM

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THE "SEAMLESS" DESIGNATION FOR SEGMENT 180 IN PG&E'S GEOGRAPHICAL INFORMATION SYSTEM

A. Introduction

PG&E's Geographical Information System (GIS) described the pipe that ruptured in Segment 180 as "seamless." As the Commission is aware, the ruptured pipe was not seamless, but rather had a longitudinally welded seam. In Directive 6, the Commission directs PG&E to (1) provide the date of the transmission of the documents or data to NTSB, (2) provide the date on which PG&E first informed the NTSB of its mistake regarding the seamless pipe at San Bruno, or the date on which NTSB informed PG&E of its mistake, and (3) explain why the data (seamless pipe) was incorrect, and when and how this occurred. PG&E provides the answers to the Commission's questions below.

B. Discussion

1. The Date of the Transmission of the Documents or Data to NTSB

In the hours following the San Bruno line rupture, and in the midst of PG&E's emergency response, the NTSB notified PG&E that it would be responding to the event and conducting an investigation. To facilitate its response, the NTSB requested that PG&E provide the pipe specifications of the involved segment as expeditiously as possible. PG&E consulted GIS, from which it could retrieve the requested information without delay. PG&E conveyed the information from GIS to the NTSB within a few hours of the rupture, before PG&E, the NTSB, or any of the other first responders had the opportunity to inspect the ruptured pipe. Thus, while the precise time is not known, PG&E provided the erroneous "seamless" information to the NTSB, along with other accurate information, in the late hours of September 9 or the early morning hours of September 10, 2010.

On September 12, 2010, the NTSB submitted a written data request to PG&E (NSTB_004-004) requesting copies of the Pipeline Survey Sheets for all of Line 132. PG&E provided the Pipeline Survey Sheets to the NTSB the same day. PG&E provided the Pipeline Survey Sheet for Segment 180 in the form as it existed before the San Bruno accident, i.e., with the erroneous "seamless" designation. *See* Pipeline Survey Sheet (Attachment #1, PG&E Response to OII Paragraph 6 ("P6-1"). As described in section 2 below, when the Pipeline Survey Sheets were provided to the NTSB, both the NTSB and PG&E were already aware that the longitudinal weld information for Segment 180 was not correct.

2. The Date on Which PG&E First Informed the NTSB of its Mistake Regarding the Seamless Pipe at San Bruno, or the Date on Which NTSB Informed PG&E of its Mistake

PG&E first responders inspected the accident site during the early morning hours of September 10, 2010. In viewing the ruptured pipe section (which was approximately 100 feet from the pipeline) and the exposed pipe that remained in the ground, PG&E personnel recognized that the pipe contained longitudinal seams. NTSB personnel arrived in San Bruno sometime later the same morning. After an off-site pre-inspection meeting, PG&E and NTSB personnel traveled to and inspected the site together, during which it was evident to the NTSB (as PG&E had previously recognized) that the involved pipe contained a longitudinal seam. Thereafter, as described below, PG&E investigated to attempt to determine the source of the incorrect GIS "seamless" designation for Segment 180.

3. Explain Why the Data (Seamless Pipe) was Incorrect, and When and How This Occurred

While the investigation is ongoing, investigation of relevant documents and historical procedures discovered to date lead to the following conclusions regarding how Segment 180 became incorrectly designated in GIS as containing "seamless" pipe.

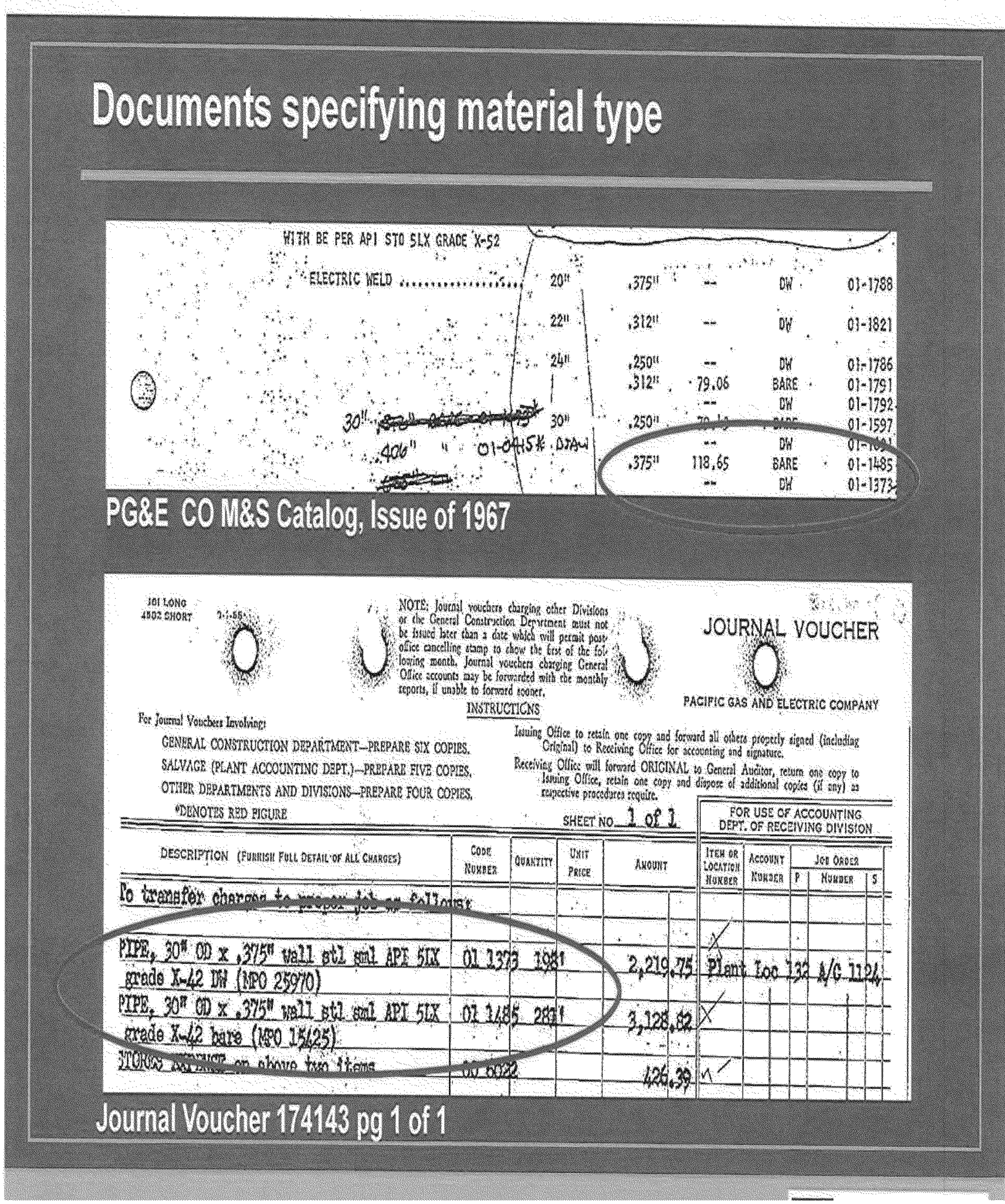
PG&E began development and implementation of GIS in the mid-to-late 1990s. During that process, in order to capture a comprehensive informational data base, PG&E utilized multiple sources to populate the data fields associated with pipe specifications. Procedurally, the relevant information was identified in the source documents and then manually entered into GIS, thereby populating the various data fields segment by segment and pipeline by pipeline. The accuracy of the manual data entry into GIS was quality checked in the final step of the process.

A foundational source of the pipeline information entered into GIS was Pipeline Survey Sheets. PG&E created Pipeline Survey Sheets in the 1960s and 1970s in accordance with 49 CFR § 192.603(b), which states, "Each operator shall keep records necessary to administer the procedures established under § 192.605." Pipeline Survey Sheets were drawn to scale and presented information regarding the pipe in each segment to which the Pipeline Survey Sheet applied. *See* Pipeline Survey Sheet (P6-1). PG&E produced Pipeline Survey Sheets for each transmission line. The information used to create the Pipeline Survey Sheets came from original construction records contained in project job files.

While not conclusive, the pertinent documents and known historical procedures suggest that, when the Pipeline Survey Sheet that includes Segment 180 was created, PG&E personnel sourced the pipe specification data, in part, from a 1956 journal voucher contained in the Segment 180 job file that identified the pipe as "30" x .375" wt sml." *See* Journal Voucher (P6-2). This journal voucher was an accounting document used in 1956 to transfer pipe costs to the Segment 180 relocation project from another project involving 30" steel pipe.

Although the journal voucher also contained the correct pipe material codes, the person populating the Pipeline Survey Sheet for Segment 180 apparently focused on the "sml" notation and interpreted it to mean "seamless" (the acronym for seamless pipe is "SMLS"). The image of the journal voucher and material codes below highlights where the information appeared:

FIGURE 5-1
PACIFIC GAS AND ELECTRIC COMPANY
SEGMENT 180 JOURNAL VOUCHER



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From this, PG&E believes that the Pipeline Survey Sheet was incorrectly populated to state that Segment 180 was constructed with 30” x .375” wall thickness seamless pipe. In turn, when GIS was developed many years later, the incorrect “seamless” designation in the Pipeline Survey Sheet was imported into GIS. Because the erroneous information originated from the 1956 journal voucher, and the error was introduced into the Pipeline Survey Sheet, the quality control process used during GIS population would not have discovered the error, *i.e.*, the Pipeline Survey Sheet created in the 1970s contained incorrect information.

Both the 1956 journal voucher and other construction documents in the Segment 180 job file denote the material codes for 30” x .375” wall thickness DSAW pipe (double wrapped and bare).[1] *See* 6-2; 6-3; 6-4. These material codes are correct; Segment 180 was constructed using DSAW pipe. The Pipeline Survey Sheet, from which GIS was subsequently populated, should have stated that the weld type on Segment 180 was DSAW, consistent with the material codes in the job file documents.

[1] DSAW is the acronym for Double Submerged Arc Welded pipe.