CHAPTER 4

APPENDIX C

CURRICULUM VITAE OF DAVID E. BULL, ARM

Curriculum Vitae

David E. Bull, ARM

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Education

1970-1972
Civil Engineering Studies
Worcester Polytechnic Institute

1973-1974
B.Sc., Natural Resource Management
University of Maine, Orono

December 1995
Associate of Risk Management (ARM)

Professional Experience

Manager
ViaData LP
1995 to present

- Co-founder and manager of ViaData LP, a software publishing firm whose mission is to publish regulatory and industry documents in an easy-to-use electronic format.
- Current products include WinDOT, *The Pipeline Safety Encyclopedia* and Manuals On-Line. Responsibilities include marketing, government liaison and new product development.
- Current services include Regulatory Compliance Training and Audits, Damage Prevention Audits, Odorization Training and Audits, Expert Witness on compliance issues.
- Member, SHRIMP software development team for Distribution Integrity Management. Duties include development of Threat Identification, Risk Ranking, Additional/Accelerated Actions, Performance Measures. Assist in developing and reviewing DIMP generated by SHRIMP.
- Contributing Editor, Pipeline and Gas Technology Magazine, author of monthly column "the Pipeline Safety Arena."
- Associate Staff instructor, PHMSA Office of Training and Qualifications.
- Currently reviewing Operations and Maintenance Manuals and Operator Qualification Plans, conducting pipeline safety regulations seminars.

1995 to present
Provided consulting, training and risk management services to the natural gas, energy and related industries d/b/a/ Taurus Risk Management, now incorporated as part of ViaData LP. Projects include:

  - Development of pipeline safety regulations and Operator Qualification Programs for Kuwait Oil Company, Kuwait.
  - Regulatory compliance training for Kuwait Oil Company, Kuwait.

- DOT Pipeline Regulations and Compliance instructor for Clarion Technical Conferences.
- Regulatory compliance audits and training for major gas, liquid and distribution pipeline operators.
- Associate Staff instructor, PHMSA Office of Training and Qualifications.
- "First Response" training for a major midwestern gas distribution system
- Odorization Audits include the Philadelphia Gas Works distribution system, Imperial Oil Company (Canada) LP bulk delivery system, and US municipal gas systems.
- Review, recommendations and enhancements for emergency response actions for a major gas distribution system.
- Expert witness and audits of damage prevention programs.

Senior Utility Consultant
AEGIS Insurance Services, Inc.
Loss Control Division
1994 to 1999

- Responsible for conducting Gas Safety Training Programs and Risk Assessments for gas and liquid pipeline operations, D.O.T. compliance programs, customer service activities and safety related issues.
- Conducted Risk Assessments for over 70 gas utility systems.
- Additional duties include consulting on accident claims, design and review of operational procedures, and research on safety issues for the gas industry.
- Developed and presented AEGIS Gas Operator Training Programs

Pipeline Safety Specialist
Transportation Safety Institute
1993 to 1994
Associate Staff Member
1994 to present

- Conducted training classes for pipeline regulatory personnel on the current D.O.T. pipeline safety regulations.
- Developed programs for and conducted seminars for state agencies, presenting regulations and safety issues to pipeline operators.
- Prepared training programs and background material for 49 CFR 190-199.
- Retained as Associate Staff 1994 to present for programs on Pipeline Failure Investigation Techniques and Pipeline Safety Regulation Application & Compliance.

Manager, Market Development
National Sales Manager
Heath Consultants Incorporated
1990 to 1993
Responsible for investigating, developing and marketing new products and services for the natural gas industry. Supervised sales force of 10 to 13 individuals. Designed and directed development of software program for field data collection and tracking of D.O.T. compliance programs.

Director of Special Services
Regional and Area Manager
Heath Consultants Incorporated
1982 to 1990
Provided corporate staff support to field sales organization. Responsible for product development. Developed and implemented various odorization programs. Designed software for computer based training.

Sales and Field Staff Positions
Heath Consultants Incorporated
1975 to 1982
Conducted leak detection surveys and other fieldwork provided by company. Responsible for all sales in a five state area.

Field Experience

Development of Kuwait Oil Company, Kuwait, Pipeline Safety Regulations
Operational Risk Assessments for Gas Distribution and Transmission Systems
DOT Regulatory Compliance Audits
Research on Regulatory Issues
Odorization System Evaluations, Audits and Training
Incident Investigation
Evaluation of Leak Detection Programs
Evaluation of Damage Prevention Programs

Training Experience

ViaData LP
Pipeline Safety Regulations and Compliance Seminars

Clarion Technical Conference
Principal Instructor for DOT Regulatory Compliance Programs
Principal Instructor and organizer for Odorization Conference.
Principal Instructor of Distribution Integrity Management Program seminar

Associate Staff Instructor for the PHMSA Office of Training and Qualifications (Transportation Safety Institute)
"Basics of Natural Gas and Leak Detection"
"Accident Investigation"
"Regulatory Enforcement"

AEGIS Insurance Services, Loss Control Division
Investigation of Leak Complaints seminars

Nationally scheduled seminars
"Odorization of Natural and LP Gas"
"Investigation of Gas Related Incidents"
"Investigation of Leak Complaints"
"Pinpointing Underground Gas Leaks"
"Instruments for Leak Detection"

Training Programs for National and Regional Gas Associations
Midwest Gas Association
Southern Gas Association

Alabama Gas Association
New England Gas Association
American Public Gas Association

Industry Committees and Association Memberships

Gas Piping Technology Committee (current member)
Operations and Maintenance Task Group
Damage Prevention/Emergency Response Task Group
Distribution Division

Member, SHRIMP Advisors committee, software development for Distribution Integrity Management

U. S. Department of Transportation, Office of Pipeline Safety
Damage Prevention Quality Action Team (Dig Safely Development Team)

American Society of Safety Engineers, 1994-2003

National Gas Rodeo, Awards Committee, 1997-1999

Published Papers

Bull, David E., (January 2011), New PHMSA Rules, *MidStream Business Magazine.*

Contributing Editor, (2009-2010). Pipeline Safety Arena monthly column, *Pipeline and Gas Technology Magazine,*

Bull, David E., (January 2010). Complying with pipeline safety regulations, *Pipeline and Gas Technology Magazine.*

Bull, David E., (April 2009). Complying with odorization regulations, *Pipeline and Gas Technology Magazine.*

Bull, David E. (January 2001). Why we need odorization audits. *Gas Utility Manager.*

Bull, David E, (May 1999). Are You Ready for Operator Qualification? *Pipeline and Gas Journal.*

Bull, David, E. (Sept. 1997). Natural Gas Safety Programs Essential for Gas Personnel and the Community. *Innovations, A Publication of the Midwest Gas Association.*

Bull, David E., (June 1993). Instruments you can use for odorization monitoring. *Gas Industries.*

Bull David E. (1993). Odorization Program Audits*. Odorization III, Institute of Gas Technology,* 671-676.

Conference Presentations

Clarion Technical Conferences, Odorization Conference.

Clarion Technical Conferences, *DOT Pipeline Safety Regulations Conferences*. Two courses per year, 2003 through 2011. One of the principal instructors teaching pipeline safety regulations and compliance for 49 CFR 191, 192 and 195.

National Association of Pipeline Safety Representatives, National Conference, September 2009, *WinDOT, The Pipeline Safety Encyclopedia, Using WinDOT effectively.*

National Association of Pipeline Safety Representatives, Eastern Region Conference, June 2008, *WinDOT, The Pipeline Safety Encyclopedia, Using WinDOT effectively.*

Pennsylvania Public Utility Commission Pipeline Safety Seminar, 2004. *Presentations on 49 CFR 192 Parts L and M, Incident Investigation and Enforcement Process.*

IGT/GTI Odorization Symposium1990, 1992, 1995, 1998, 2000, 2001, 2002, 2004. Papers presented on “*Odorization Audits*” and "*Odorization Training to meet OQ Requirements*".

Appalachian Gas Measurement Short Course 2003, 2004. *Odorization: A Discussion Of Code Compliance And Liability Issues*

Appalachian Gas Measurement Short Course, 1998. *Odorization Audits.*

Alabama Gas Association, 2000 Gas Operations Meeting, *Electronic Pipeline Safety Resources.*

National Association of Pipeline Safety Representatives, Southwest Region Fall 2000 Conference, *Electronic Pipeline Safety Resources.*

Tennessee Gas Association, 2000 Gas Operations Conference, papers on Odorization and Evaluating Damage Prevention Programs.

Minnesota Office of Pipeline Safety, 1999 Fall Education Conference, *The Importance of Odorization to a Gas Utility.*

Pacific Coast Gas Association, Damage Prevention Workshop, 1998. *Risk and Liability Issues for Damage Prevention Programs.*

Institute of Gas Technology, 1997, 1998, 2000 *“Odorization Fundamentals” program.*

Midwest Gas Association Operations Conference, 1997. *Risk and Liability Issues for Leak Survey and Damage Prevention Programs.*

Midwest Gas Association Operations Conference, 1996. *Accident Investigation*.

AGA Annual Transmission/Distribution Conference, 1992. *Instruments for Odorization Monitoring.*

CHAPTER 4

APPENDIX D

COMPLETE LIST OF DOCUMENTS REVIEWED

Documents reviewed for testimony in Recordkeeping Order Instituting Investigation Proceeding, I.11-02-016

Company-wide Emergency Plan in effect as of the San Bruno rupture (version provided in Recordkeeping Order Instituting Investigation proceeding in response to Legal Division Data Request 1, Question 8)

Peninsula Division Emergency Plan in effect as of the San Bruno Rupture (version provided in Recordkeeping Order Instituting Investigation proceeding in response to Legal Division Data Request 1, Question 8)

Gas Transmission & Distribution Emergency Plan Manual in effect as of the San Bruno rupture (version provided as exhibit P3-30152 in June 20, 2011 filing in Recordkeeping Order Instituting Investigation proceeding)

Gas Transmission System Incident Response Plan (version provided in Recordkeeping Order Instituting Investigation proceeding in response to Legal Division Data Request 1, Question 8)

Pacific Gas and Electric Company, Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010, NTSB San Bruno Pipeline Accident Report, August 30, 2011, NTSB/PAR-11/01, PB2011-916501

Consumer Protection & Safety Division, Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno, California, released January 12, 2012

Revised Report and Testimony of Margaret Felts (I.11-02-016), March 12, 2012, available at http://www.cpuc.ca.gov/PUC/events/120312_ReferenceDocumentsforCPSDReportsinRecordkeepingPenaltyConsiderationCase.htm

Index of Exhibits to Margaret Felts Testimony, available at http://www.cpuc.ca.gov/PUC/events/120312_ReferenceDocumentsforCPSDReportsinRecordkeepingPenaltyConsiderationCase.htm

"Excerpt_ER_Confusion," available in Index of Exhibits to Margaret Felts Testimony, ftp://ftp.cpuc.ca.gov/pipelinerecordkeeping/ExhibitsToReportTestimonyOfMargaretFelts

PG&E Gas Operator Qualification Plan Abnormal Operating Conditions, Supplement to Basic Plan 1.1.2 Definition, Abnormal Operating Conditions Job Aid

PG&E DOT Operator Qualification Evaluation form, Inspect/Maintain Emergency Valves subtask, 17-01.00

CHAPTER 4

APPENDIX E

ENFORCEMENT GUIDE FOR §192.615

Existing Code Language:	(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following: (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator. (2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials. (3) Prompt and effective response to a notice of each type of emergency, including the following: (i) Gas detected inside or near a building (ii) Fire located near or directly involving a pipeline facility (iii) Explosion occurring near or directly involving a pipeline facility (iv) Natural disaster (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency. (5) Actions directed toward protecting people first and then property. (6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property. (7) Making safe any actual or potential hazard to life or property. (8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency. (9) Safely restoring any service outage. (10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible (b) Each operator shall: (1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures. (2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective. (3) Review employee activities to determine whether the procedures were effectively followed in each emergency. (c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to: (1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency; (2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency; (3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and, (4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

Origin of Code	192-24, 03-31-76
Last FR Amendment	192-71, 02-11-94
Interpretation Summary	Date: 06-17-97 Section §192.615(a)(3)(i) allows operators latitude in responding to notices of gas odor inside buildings. As long as an operator's response is "prompt" and is "effective" in minimizing the hazard, there would be little reason, if any, to challenge the appropriateness of the operator's procedures. Given the pros and cons of taking time in a gas emergency to open windows and doors before exiting, we do not think there is sufficient reason to challenge the effectiveness of a response that tells callers to exit quickly without stopping to open windows and doors.
Interpretation Summary	Date: 02-23-94 Advisory Bulletin ADB 94-03 Pipelines in a common right-of-way, parallel right-of-way, or cross a railroad right-of-way
Interpretation Summary	Date: 02-04-93 This responds to your letter of December 15, 1992, in which you ask us to clarify the requirements in §§192.615(c) and 195.402(c)(12) regarding the requirements to "...establish and maintain liaison with appropriate fire, police, and other public officials..." In complying with §§192.615(c) and 195.402(c)(12), operators must meet face-to-face with public officials and maintain an ongoing face-to-face liaison after the initial meeting.
GPTC	Industry guidance available.
Other Ref. Material & Source	None noted

New Guidance Material	- Core emergency plans are fine for the whole company; however, there must be site-specific information about area locations covered by the locally-applied emergency plan. §192.615(a) - Cross references must be included in the emergency plan, if material in other manuals are to be used at the incident site (i.e. Safety Manuals, etc.). §192.615(a) - Individuals who normally receive calls for the operator should be appropriately trained to identify the situation, direct callers to seek safety first, and then gather critical information to promptly initiate the operator=s response efforts. §192.615(a) - It is permissible to have on-line access to an electronic copy of the Emergency Plan; however, appropriate portions of the plan must be readily accessible locally, even if network connectivity to headquarters is temporarily not available. The same is true for maps showing the location of emergency valves and other pertinent information. §192.615(b) - Emergency training programs typically include mandatory initial employee training, with periodic individual refresher training. The operator should require and Atrack@ individual employee training frequencies. §192.615(b) - Emergency training should cover different levels of responsibility and complexity, including, as applicable to the operator, personnel from the control center, managers and/or supervisors, field personnel, patrol pilots, communications systems, SCADA systems, etc. §192.615(b) - Emergency exercises are not mandatory but are recommended. They may include Atabletop@ scenarios, on-scene Amock@ and/or corporate-wide exercises, simulated control room exercises, etc. §192.615(b) - One method operators use to review performance, make appropriate changes, and verify that supervisors maintain a thorough knowledge, is by critiquing the performance of emergency exercises. All simulated and real emergencies should be self-critiqued, with deficiencies identified and recommendations made and followed up on. §192.615(b) - It is acceptable to use third parties to conduct meetings with appropriate public officials on behalf of the operators; however, the operator is ultimately responsible for compliance with this requirement. §192.615(c) - Documentation must be kept concerning a good faith attempt, and include who was invited, who attended, and topics discussed. §192.615(c) - Appropriate materials must be sent to the public officials that were invited but did not attend. §192.615(c) - The operator should make reasonable attempts to conduct face-to-face meetings with local public officials. §192.615(c)

Examples of a Violation	- Statements indicating that they treat all incidents as emergencies and have no provisions for prioritizing multiple events that could occur at the same time. - No listing of where pretested emergency pipe is located. - No listing for the railroad road-master or individual with the authority to shut-down a segment of a railroad that parallels a pipeline in their assigned area. - Maps that have not been revised or red lined to show modifications to essential facilities, as in removal or addition of emergency valves. - Control displays or other aids that have not been revised to show modifications to essential facilities, as in removal or addition of emergency valves. - Lack of training related to emergency response. - A written, continuing training program has not been established. - Training program procedures are/have not been followed. - No documentation of the required review of emergency procedures used during recent emergencies. - Omission of invitations for certain public officials for liaison meetings. - Insufficient documentation of the materials sent or provided to public officials about liaison meetings. - No documentation of attempts to meet with appropriate public officials. -The procedure parrots the regulation.
Evidence Guidance	- Copy of emergency procedures or applicable portion that shows omission or deficiency in the plan. - Documented conversations with operator personnel who are charged with establishing the plan. - Documentation of meetings, invitation lists, and list of those that attended the meeting.
Other Special Notations	None noted

CHAPTER 4

APPENDIX F

GPTC GUIDE MATERIAL FOR §192.615

Guide material 192.615 Emergency plans

This guide material is under review following Amendment 192-112.

1 WRITTEN EMERGENCY PROCEDURES (§192.615(a))

(a) Written procedures should state the purpose and objectives of the emergency plan and provide the basis for instructions to appropriate personnel. The objective of the plan should be to ensure that personnel who could be involved in an emergency are prepared to recognize and deal with the situation in an expeditious and safe manner.
(b) Establishing written procedures may require that parts of the plan be developed and maintained in coordination with local emergency response personnel (e.g., police, fire, and other public officials) and with other entities in or near the pipeline rights-of-way (e.g., other utilities, highway authorities, and railroads) that may need to respond to a pipeline emergency.
(c) Written procedures should also include instructions on interfacing with the Incident Command System (ICS) typically used by emergency responders. See 1.2 below for interfacing with an ICS and 1.10 below for general information about the ICS.
(d) To ensure the safety of the general public, written procedures should provide for the following as applicable.

1.1 Receiving, identifying, and classifying emergencies.
(a) Provisions should be made to ensure prompt and adequate handling of all calls, reports, or indications concerning emergencies (see §192.615(a)(3)), whether they are from customers, the public, operator employees, SCADA systems, or other sources. The following should be included.
  (1) Arrangements for receiving notification of an emergency at any hour of the day. When an answering service is used, personnel should be trained and have updated emergency call-out lists of operator personnel for emergency response.
  (2) Directions to employees who receive calls considering the following.
    (i) The information received should be assessed in order for the operator to react properly to the call and to inform the caller of precautionary actions to be taken prior to operator personnel arrival. Personnel receiving notices of gas leaks or odors should obtain the following basic information from the caller, and inform the caller that access will be required.
      (A) Name.
      (B) Address of leak or odor.
      (C) Telephone number.
      (D) Reason for call.
      (E) Location of the odor (inside or outside).
    (ii) Additional questions that could be asked to assist in determining the priority for action, and if additional instructions should be provided to the caller, include the following.
      (A) Strength of odor?
      (B) Length of time odor has been present?
      (C) Was anyone working on indoor gas piping or appliances?
      (D) Is there any construction in the area?

(E) Can you hear evidence of escaping gas?
(F) What type of building or facility is involved?

(iii) If the answers to these or other questions indicate a potentially hazardous situation, consideration should be given to providing additional instructions to the caller, such as the following.

(A) Do not create a source of ignition by operating switches, electrical appliances, or portable telephones.
(B) Evacuate the area and wait for operator personnel to arrive.
(C) Call back from a safe location to provide additional information for response personnel.

(iv) If leakage of gas or the hazard is determined to be significant, the operator should consider contacting the local emergency response agency, such as the fire or police department. The operator should call 911 where appropriate, informing them of the emergency situation and providing pertinent information.

(3) Personnel receiving emergency calls should receive periodic refresher training on leak call procedures, communication skills, and reporting procedures. Periodic performance reviews should be conducted during actual leak calls.

(b) Instructions to operator personnel should ensure that the information received is evaluated to determine the priority for action. Some situations call for personnel to be dispatched promptly for an on-the-scene investigation. Personnel should respond in an urgent manner giving a potential emergency top priority until the severity of the situation has been determined. Some situations require that priority be given to other actions, such as notification of gas control or emergency response personnel. See 3.3 below.

Emergency situations that require immediate response may include the following.

(1) Gas ignition or explosion.
(2) A hissing noise is present or there is any indication of a broken or open-ended pipe.
(3) Report of a pulled service or damaged facility.
(4) Gas odor throughout the premise or building.
(5) Other identified (i.e., operator designated) emergencies.

1.2 Establishing and maintaining adequate means of communication.

(a) Arrangements made for establishing and maintaining adequate public and operator communications should be described. These arrangements should include means of communication with appropriate fire, police, and other public officials, and should consider the need for the following.

(1) Continuously updated operator and public emergency call lists that will show how to contact personnel that may be required to respond to an emergency at any hour.
(2) Multiple telephone trunk lines to the emergency operations center.
(3) Additional switchboard facilities and personnel.
(4) "Unlisted" telephone service to ensure accessibility to operator-only calls.
(5) Additional fixed and mobile radio equipment.
(6) Standby electrical generating equipment for communications power supply.
(7) Dissemination of accurate information to the news media and cooperation with the news media on the scene.

(b) Instructions for working effectively with the ICS should be described as follows.

(1) When emergency responders have set up an Incident Command prior to the arrival of operator personnel:

(i) The first person to arrive should introduce himself to the Incident Commander as the representative from the gas pipeline operator, and

(ii) That person remains the point of contact until the incident has been made safe or until he has been relieved of that duty by another gas pipeline operator representative.

(2) When emergency responders are not yet on the scene:

(i) The first person representing the operator to arrive will serve as Command, and

(ii) That person assesses the situation and takes, or directs, all necessary actions to protect people, protect property, and secure the flow of gas.

(3) If emergency responders arrive later and set up an ICS:

(i) The Command for the gas pipeline operator should introduce himself as the point of contact for the operator, brief the Incident Commander, and

(ii) That person remains the point of contact until the incident has been made safe or until being relieved of that duty by another operator representative.

1.3 Prompt and effective response to each type of emergency.

Various types of emergencies will require different responses in order to evaluate and mitigate the hazard. Consideration should be given to the following.

(a) Emergencies involving gas detected in or near buildings should be prioritized in order to have sufficient personnel for response. For leak classification and action criteria, refer to Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems. See § 192.605(b)(11), which requires procedures for prompt response to reports of a gas odor in or near buildings.

(b) Emergencies involving damage to buried facilities during excavation activities should be assessed for potential hidden and multiple leak locations.

(c) Emergencies involving fire located on or near pipeline facilities may require those facilities to be isolated. If a major delivery point is involved, an alternative gas supply may be needed.

(d) Emergencies involving an explosion on or near pipeline facilities may result in damage from fire and shock waves.

(e) Natural disasters, such as earthquakes, floods, hurricanes, tidal waves, or tornadoes, may affect the safe operation of pipeline facilities in many different ways. Operator personnel should be dispatched to affected areas as soon as possible to evaluate the situation and proceed with emergency response, as necessary, to keep or make conditions safe. Operators of pipeline facilities subject to natural disasters should consider preparing a natural disaster plan. The plan may include the following.

(1) Information on responsibilities for operator personnel communication and work assignments.

(2) Information on alternative reporting locations for operator personnel in case the primary location is damaged or inaccessible.

(3) Procedures to assess damage and mitigate hazardous conditions, which may include the following.

(i) Establishing an operations and communications command center.

(ii) Establishing a field command post.

(iii) Determining manpower, material, and equipment requirements.

(iv) Deploying personnel so that they will be in position to take appropriate actions, such as shutdown, isolation, or containment.

(v) Evaluating the accessibility of pipeline facilities that may be in jeopardy.

(vi) Performing frequent patrols to evaluate the effects on pipeline facilities.

(vii) Determining the extent of damage to pipeline facilities.

(4) Procedures to re-establish normal operations including service restoration and progress tracking and reporting. See Guide Material Appendix G-192-7 for guide material related to large-scale outages of distribution systems.

(5) Other considerations.

(i) Maintaining mutual assistance agreements with other operators.

(ii) Providing accommodations for operator personnel and other assisting personnel.

1.4 Assuring the availability of personnel, equipment, tools, and materials.

Arrangements made to assure the availability of personnel, equipment, tools, and materials that may be needed should be described in accordance with the type of emergency. These arrangements should include the assignment of responsibilities for coordinating, directing and performing emergency functions, including the following.

(a) Responsibility for overall coordination, which may be at the local headquarters or at the operating executive level, depending on the scope of the emergency.

(b) Responsibility for execution of emergency operations, based on the scope of the emergency.

(c) Determination of departmental functions or services during an emergency, including determination of individual job assignments required to implement the plan.

(d) Determination of coordination required between departments, including provision for bypassing the normal chain of command as necessitated by the emergency.

(e) Determination of coordination required to implement mutual aid agreements.

(f) Responsibility for providing accurate information and cooperation with the news media.

1.5 Controlling emergency situations.

Actions that may be initiated by the first employee arriving at the scene in order to protect people and property should be described. These actions may include the following.

(a) Determining the scope of the emergency.

(b) Evacuating and preventing access to premises that are or may be affected.

(c) Preventing accidental ignition.

(d) Reporting to the appropriate supervisor on the situation and requesting further instructions or assistance, if needed.

1.6 Emergency shutdown and pressure reduction.

(a) Provisions for shutdown or pressure reduction in the pipeline system as may be necessary to minimize hazards should be described. The plans should include the following.

(1) Circumstances under which available shutdown, pressure reduction, or system isolation methods are applicable. Considerations should include access to, and operability of, valves located in areas prone to high water or flooding conditions.

(2) Circumstances under which natural gas might be allowed to safely escape to the atmosphere (i.e., vent) until shutdown or repair.

(i) Some possible reasons for using this alternative are as follows.

(A) Curtailment will affect critical customers (e.g., hospitals).

(B) Curtailment will affect large numbers of customers during adverse weather conditions.

(C) Line break or leak is remotely located and does not cause a hazard to the public or property.

(ii) Some factors to consider are as follows.

(A) Sources of ignition.

(B) Leak or damage location (rural vs. urban).
(C) Proximity to buildings and other structures.
(D) Ability to make and keep the area safe while gas vents.
(E) Ability to coordinate with other emergency responders and public officials.

(3) Lists or maps of valve locations, regulator locations, compressor schematics, and blowdown locations.
(4) Maps or other records to identify sections of the system that will be affected by the operation of each valve or other permanent shutdown device.
(5) Provision for positive identification of critical valves and other permanent facilities required for shutdown. See 3.2 of the guide material under §192.605.
(6) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
(7) Provisions for notifying affected customers.
(8) Provisions for confirming that the shutdown or pressure reduction was effective.

(b) Distribution system plans should include consideration of the potential hazards associated with an outage and the need to minimize the extent of an outage, and to expedite service restoration. In addition to the use of any existing emergency valves within a distribution system, consideration should also be given to other methods of stopping gas flow, such as:
(1) Injecting viscous materials or polyurethane foam through drip risers or any other available connections to the main.
(2) Use of squeeze-off or bagging-off techniques.

1.7 Making safe any actual or potential hazard.

Provisions should be described for identifying, locating, and making safe any actual or potential hazard.

These may include the following.

(a) Controlling pedestrian and vehicular traffic in the area.
(b) Eliminating potential sources of ignition.
(c) Controlling the flow of leaking gas and its migration. See Guide Material Appendices G-192-11 for natural gas systems and G-192-11A for petroleum gas systems.
(d) Ventilating affected premises.
(e) Venting the area of the leak by removing manhole covers, barholing, installing vent holes, or other means.
(f) Determining the full extent of the hazardous area, including the discovery of gas migration and secondary damage such as the following.
(1) Deformation of a gas service line indicating that the service line might be separated underground near a foundation wall or at an inside meter set assembly.
(2) Multiple underground leaks that may have occurred, allowing gas to migrate into adjacent buildings.
(3) Potential pipe separation and gas release at unseen underground locations that may result in gas entering adjacent buildings, or following or entering other underground structures connected to buildings.

(g) Monitoring for a change in the extent of the hazardous area.
(h) Determining whether there are utilities whose proximity to the pipeline may affect the response.
(1) Visually identify the presence of electric and other utilities surrounding the pipeline facility.

(2) Evaluate the potential risk associated with the continued operation of the surrounding utilities.
(3) Use the ICS to contact the owner of the surrounding utilities, as necessary, to implement a more effective and coordinated emergency response.

(i) Coordinating with fire, police, and other public officials the actions to be taken.
(j) Maintaining ongoing communication with fire, police, and other public officials as events unfold to ensure that information pertinent to emergency response is shared in a timely manner.

1.8 Restoration of service.

Planning for the safe restoration of service to all facilities affected by the emergency, after proper corrective measures have been taken, should include consideration of the following.

(a) Provisions for safe restoration of service should include the following.
(1) Turn-off and turn-on of service to customers, including strict control of turn-off and turn-on orders to assure safety in operation.
(2) Purging and repressuring of pipeline facilities.
(3) Resurvey of the area involved in a leak incident to locate any additional leaks.

(b) Execution of the repair and restoration of service functions will necessitate prior planning, such as the following.
(1) Sectionalizing to reduce extent of outages and to expedite turn-on following a major outage.
(2) Lists and maps for valve locations, regulator locations, and blowoff or purge locations.
(3) Provisions for positive identification of valves and regulator facilities. See 3.2 of the guide material under §192.605.
(4) Equipment checklist for repair crews.
(5) Instructions for operating station blowdown and isolation systems for each compressor station. See Guide Material Appendix G-192-12.
(6) Emergency supply connections with other gas companies and procedures for making use of such connections.
(7) List of contractors, other utilities, and municipalities that have agreed to provide equipment and workmen to assist with repair and service restoration. Procedures for securing and utilizing this manpower and equipment should be described.
(8) Prearranged use of facilities, owned by others, for temporary operating headquarters for repair and restoration activities. Arrangements should also be made for all necessary support functions for such temporary operating headquarters.
(9) Cooperation with appropriate civil organizations in providing housing and feeding facilities for persons requiring shelter during an outage in severe weather.
(10) Arrangements to maintain service to critical customers, such as hospitals, to the degree possible during a general service curtailment or outage. In addition, a similar priority should be assigned for turn-off activities.

(c) For large-scale outages, also see Guide Material Appendix G-192-7.

1.9 Providing for investigation of failures.

Instructions for initiating investigation of failures in accordance with §192.617 should include the following, where applicable.

(a) Keeping a log of significant events and of actions taken.
(b) Preservation of failed facilities or equipment for analysis, as may be appropriate.
(c) Obtaining and submitting information required by jurisdictional regulatory agencies.

1.10 Incident Command System (ICS).

(a) In the context of applying the ICS, the Federal Emergency Management Agency (FEMA) has defined the term incident as "an occurrence, either caused by humans or natural phenomena, that requires response actions to prevent or minimize loss of life or damage to property and/or the environment." Certain gas emergencies could fall within the FEMA definition of an incident. Examples of FEMA incidents include the following.

(1) Fire, both structural and wildland.

(2) Natural disasters, such as tornadoes, floods, ice storms, or earthquakes.

(3) Human and animal disease outbreaks.

(4) Search and rescue missions.

(5) Hazardous materials incidents.

(6) Criminal acts and crime scene investigations.

(7) Terrorist incidents, including the use of weapons of mass destruction.

(8) National Special Security Events, which are designated by the U.S. Department of Homeland Security (e.g., Presidential inaugurations, national political conventions, Super Bowls).

(9) Other planned events, such as parades or demonstrations.

(b) The ICS is a management system for dealing with emergencies. It has been developed from reviewing past emergencies and formalized into a structured system by FEMA and other emergency response agencies. It is a consistently applied system for controlling on-site personnel, facilities, equipment, and communications in an emergency. It is a designated system used from the time a FEMA incident occurs until the requirements for implementing the ICS no longer exist.

(c) When an operator and other emergency responders implement an ICS, respective plans may differ but should be based on similar principles so the plans are compatible. The ICS may be used for small or large incidents, remaining adequately flexible to adjust to the changing needs of an incident.

(d) The ICS functions typically include the following.

(1) Safety - public and employees.

(2) Security - utilize public safety personnel.

(3) Commander responsibilities - establish command center, transfer of command.

(4) Operational - incident stabilization plan, repair plan.

(5) Logistics - material, equipment, other resources.

(6) Public relations - communications, notifications, information liaison.

(7) Personnel management.

(e) The ICS supports responders and decision makers by providing the data they need through effective information and intelligence management. The data provided may include information on the following.

(1) Maps and records for critical infrastructure and other facilities.

(2) Load studies.

(3) Affected customers, including residential, commercial, and industrial customers.

(f) Additional information on the ICS can be found at www.training.fema.gov/EMIWeb/IS/ICSResource/index.htm.

2 ACQUAINT APPROPRIATE OPERATING AND MAINTENANCE EMPLOYEES WITH THE PROCEDURES (§192.615(b))

Each operator should have a program to assure that all operating and maintenance personnel who may be required to respond to an emergency are acquainted with the requirements of the written emergency procedures. The program should include the following.

2.1 Provide employees access to emergency procedures manual.
The latest edition of the written emergency procedures and plans should be easily accessible so that employees may become familiar with them. Consideration should be given to placing a copy near telephones and base radio units that might be used to notify the operating personnel of an emergency.

2.2 Training of employees.
Appropriate operating and maintenance employees should be trained to ensure that they are knowledgeable of the requirements of the written emergency procedures. Persons providing training of the emergency procedures should be knowledgeable in emergency response and training techniques. Consideration should be given to conducting classroom or field simulated emergency exercises involving appropriate personnel, such as operating, maintenance, and dispatch personnel, including those monitoring and controlling operations of remote facilities. Emergency exercises should include worst-case scenarios. The effectiveness of the training may be verified by methods such as oral test, written test, or evaluating performance during simulated emergencies. Such verification of the effectiveness of training should be documented.

Those responsible for instruction of employees should place special emphasis on the following.

(a) Understanding the properties and behavior of the gas, as related to types of potential hazards, including the recognition of, and the appropriate actions to take regarding, hazardous leaks.
(b) Coordinated execution of the operator's written emergency procedures, including coordination among different functional groups (e.g., between gas control and emergency response personnel in an emergency situation).
(c) Knowledge of how emergency control is exercised in various sections of the system, including identification and operation of key valves.
(d) Ability to use operator's maps or other facility records.
(e) Responsibilities of each employee responding to an emergency and the relationship to the emergency procedure. This should include responsibilities related to interacting effectively with emergency responders in an Incident Command System.
(f) Evaluation of reports of gas odor and other potential emergencies.
(g) Response to different types of emergency situations, such as gas escaping inside or outside and gas burning inside or outside. Appropriate actions should include avoiding the use of doorbells or buzzers when responding to possible leaks, evacuation, elimination of ignition sources, gas shutoff, ventilation, and other precautionary measures.
(h) Familiarization with tools and equipment appropriate to the particular function or situation.
(i) Fulfillment of the record-keeping requirements called for under the written emergency procedures. This should include a log of the emergency and the validation and documentation of the corrective action taken.

2.3 Review of employee activities.
Following each emergency, employee activities should be reviewed, by examining the log of events and actions taken, to determine whether the procedures were effectively followed. Consideration should be given especially to whether responses to the emergency were timely. In

addition, consideration should be given to the need for changes in the written procedures as may be indicated by the experience gained during the emergency.

3 LIAISON WITH PUBLIC OFFICIALS (§192.615(c)) AND OPERATORS OF FACILITIES IN THE VICINITY OF THE PIPELINE

Note: Section 192.616 requires most operators to develop and implement a written continuing public education program that follows the guidance provided in API RP 1162 for liaison with emergency officials, which is a requirement of §192.615(c). Added guidance for liaison with emergency officials is provided below.

Those responsible for establishing liaison with appropriate public officials and operators of facilities in the vicinity of the pipeline (e.g., telephone, electric, gas, cable, water, sewer, and railroads), with respect to emergency procedures, should consider the following.

3.1 Compiling current information on the resources of government organizations.

(a) Organization's name.
(b) Type of responsibility.
(c) Geographic area covered.
(d) Availability to assist in case of a pipeline emergency.
(e) Responsibility and resources for fire, bodily injury, control, and area evacuation problems in connection with a gas pipeline emergency.
(f) Type, size, and capacity of equipment and vehicles.
(g) Procedures to facilitate prompt communications in emergencies.
(h) Level of training of responders.

3.2 Acquainting public officials with emergency procedures.

(a) Appropriate fire, police, and other public officials should be informed of the availability, capability and location of the operator's personnel, equipment, and materials for response to gas pipeline emergencies. They should be provided with a list of the appropriate employees who can be contacted at any hour. The importance of immediate contact should be stressed.
(b) Consideration should be given to involving local public emergency response personnel in operator-simulated emergency exercises and post-exercise critiques. In areas where multiple pipeline operators have facilities, consideration should be given to joint emergency training and liaison activities with the local emergency response officials.

3.3 Identifying emergencies that require notification to and from public officials.

(a) The types of emergencies that might require notification of public officials by gas system operators include the following.
  (1) A serious fire or a fire on adjacent property.
  (2) Serious bodily injury.
  (3) Where the number of people involved or the spectators are too numerous for the operator to handle.
  (4) Adjacent to public rights-of-way where the public could be endangered.
  (5) Where an area patrol or area evacuation is needed.
  (6) An incident in a highly populated area.
(b) The types of emergencies that might require notification to operators by public officials include the following.

(1) Report of gas odor.
(2) Damage to gas facilities.
(3) Operation of a gas system valve by non-operator personnel.
(4) Report of a gas outage.

3.4 Plan with public officials and operators of facilities in the vicinity of the pipeline for mutual assistance.

(a) Operator personnel should establish and maintain liaison with appropriate fire, police, and other public officials and operators of facilities in the vicinity of the pipeline to plan how to engage in mutual assistance to minimize hazards to life and property. This planning should include how to work together effectively in an Incident Command System. Consideration should be given to various situations including the following.
  (1) Situations where the operator has reason to believe a hazard may exist and where other emergency personnel, such as fire and police, may be able to respond more quickly than operator personnel. Fire and police department personnel should take action toward protecting the public by means of evacuation and building ventilation, where needed, pending the arrival of operator personnel.
  (2) Situations that involve the evacuation of buildings and properties.
    (i) Advise police and fire departments that operator personnel may need to conduct leak investigations inside buildings and on properties within the area of the emergency.
    (ii) The operator, police department, and fire department should plan for access to evacuated buildings and properties. The plan should include provisions to instruct personnel in charge of evacuated buildings and properties to provide a means of access, when required.
  (3) Situations where the operation of electric or other utilities located in the vicinity of the pipeline may provide sources of ignition for the gas released, may increase burning time or intensity of fires that have already started, or may delay responders who are attempting to make the situation safe.
  (4) Means of ensuring that communication is ongoing during the emergency response so that pertinent information is shared in a timely manner.

(b) The gas characteristics and properties, such as pressure, specific gravity, gas odor, and flammability limits, should be provided to emergency response officials. The implications of these characteristics and properties on emergency response decisions should be thoroughly discussed. In discussions with emergency response officials, the operator should emphasize the following.
  (1) The importance of this information to outside emergency response personnel arriving before operator personnel.
  (2) The use of this information in making decisions, such as areas to be evacuated, traffic rerouting, and control of ignition sources.
  (3) The importance of gas detectors in properly responding to an incident.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

RECORDS ALLEGATIONS AND THE SAN BRUNO ACCIDENT

TABLE OF CONTENTS

Page

CHAPTER 4A SEGMENT 180 RECORDS RELATED TO CONSTRUCTION AND RECONDITIONED PIPE 1

1. PG&E's Records for Salvaged Pipe on Segment 180 1

2. PG&E's Records from the Construction of Segment 180 4

CHAPTER 4B POST-INSTALLATION PRESSURE TEST AND RECORDS FOR SEGMENT 180... 6

CHAPTER 4C RECORDS USED BY PG&E TO ESTABLISH MAOP FOR LINE 132 8

CHAPTER 4D MILPITAS TERMINAL ON SEPTEMBER 9, 2010 13

1. Alleged Failure to Follow Clearance Work Procedure 13

   a. The September 9, 2010 Clearance for Milpitas Terminal........ 13

   b. PG&E's Actions to Revise the Clearance Procedure 15

2. Milpitas Terminal Operations & Maintenance Instructions Manual.. 17

3. Milpitas Operating Diagram and SCADA Display 18

   a. Operating Diagram 19

   b. SCADA Display... 20

4. Back-up Software at Milpitas Terminal 23

CHAPTER 4E SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA) SYSTEM 26

1. SCADA and Gas Control on September 9, 2010............................... 26

2. PG&E's Actions to Improve its SCADA System 29

   a. Automated Valve Program... 30

TABLE OF CONTENTS
(continued)

Page

b. OSIsoft PI Data Historian Integration with SCADA and GIS 32

c. Distribution Control Center Creation 34

CHAPTER 4F PG&E'S EMERGENCY RESPONSE 35

1. PG&E's Plans 35

2. Applicable Regulations 35

3. CPSD's Reviews of PG&E's Emergency Plan Indicate Satisfaction with PG&E's Plan 36

4. Allegation that Transcript from Control Room Demonstrated Confusion 37

CHAPTER 4G EXPERT REVIEW OF PG&E'S EMERGENCY RESPONSE PLAN 39

1. Qualifications 39

2. Introduction 39

3. Review of PG&E Emergency Plan and Compliance with Federal Regulation 49 C.F.R. § 192.615 40

4. Plan Organization and Compliance 43

5. Regulatory Approach to Required Manuals under Part 192 46

6. Industry Guidance and Practice 50

7. Allegation that Plan is Too Complex 51

8. Control Room Transcript Review 54

9. Conclusions 55

CHAPTER 4A
SEGMENT 180 RECORDS RELATED TO CONSTRUCTION AND RECONDITIONED PIPE

CPSD alleges that PG&E violated Section 451 because PG&E does not have "records for salvaged pipe installed into Segment 180."[1] CPSD asserts that this violation continued from 1951 to 2010, and possibly as far back as 1911.[2] CPSD further asserts that PG&E violated Section 451 because it failed "to create/retain construction records for" the 1956 Segment 180 project, and asserts that this violation spans from 1956 to 2010.[3]

1. PG&E's Records for Salvaged Pipe on Segment 180

PG&E acknowledges that it cannot conclusively document the origin of the pipe used in the construction of Segment 180. PG&E did not purchase pipe for the Segment 180 relocation project. PG&E completed the installation using 30-inch DSAW pipe held in existing inventory. PG&E's records show that it had sufficient 30-inch DSAW pipe remaining in 1956 from prior pipe purchases to complete the Segment 180 project with pipe previously ordered but not used on projects in 1948 (Line 132), 1949 (Line 153), and 1953 (Line 131). (NTSB Docket No. SA-534, Exhibit 2-AF (Ex. 4-1); PG&E's Response to Legal Division Data Request 3, Question 11 (Ex. 4-2).) PG&E conducted an internal camera inspection of Segment 180 following the accident, which confirmed through stencils and markings seen inside the pipe that Segment 180 was constructed at least in part with pipe from these prior purchases. (Ex. 4-1; Ex. 4-2.)

Segment 180 job documents reflect that, in total, 1,851 feet of pipe were used on the Segment 180 project. (Segment 180 Project File (P3-30010).) Specifically, project documents show that pipe totaling 1,290 feet was requisitioned and delivered from a PG&E storage facility to the job site. (Material Procurement Forms (P1-1).) Based on the material codes on these documents, this pipe remained in inventory from the prior purchases of 30-inch DSAW pipe noted above. (Material Codes (1967), p. 5 (P1-2).)

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[1] Felts Supplement at 10.

[2] Felts Supplement at 10, nn.19-20.

[3] Felts Supplement at 10.

Other documents in the Segment 180 job file account for the remaining footage of pipe used on the project, most of which also include material code references corresponding to new pipe. (P3-30010; Ex. 4-2.) Most of the pipe was delivered to the construction site double-wrapped to protect against external corrosion.

Segment 180 job file documents do not foreclose the possibility that some of the pipe used on the Segment 180 job may have been reconditioned pipe. That level of material tracking was uncommon in that era. As more fully discussed in Chapter 3.A, there were no regulations in 1956 regarding recordkeeping for the gas pipeline industry, nor were there industry standards and practices related to tracking the reconditioning and reuse of pipe. Thus, the absence of a tracking system for reused pipe, or pipe records specifically documenting the origin of all of the joints or pipe used in Segment 180, did not contravene any regulation or industry standard when Segment 180 was constructed in 1956. As discussed more fully in Chapter 1.B and 3.A, when regulations were ultimately adopted by state and federal authorities, existing facilities were exempted insofar as their initial design, construction and testing were concerned. The decision to grandfather these existing facilities impacts our expectations about the quality of design basis and testing records for these pipes.[4]

As described in Chapter 3.C, the use of reconditioned and reused pipe was a common and accepted practice in the time period that Segment 180 was constructed. Properly reconditioned pipe is safe, durable and reliable. ASA B31.1.8-1955 expressly provided for the use of reconditioned pipe, as does the current version of that standard, though neither version addressed tracking or recordkeeping related to reused pipe. (ASA B31.1.8-1955, § 811.27; ASME B31.8-2010, § 817.)

GO 112 and each of its subsequent iterations until the adoption of GO 112-C incorporated the ASME standards and the provisions regarding the

[4] For instance, when state regulations were first adopted in December 1960, and federal regulations adopted in 1970, existing pipelines were excluded from pressure test requirements. The federal regulations, in 49 C.F.R. § 192.619(c), “grandfathered in” existing pipelines based on prior operating pressure history, and did not require that existing pipelines be pressure tested to establish the appropriate MAOP.

use of reconditioned pipe.[5] At no time did the Commission add to the ASME standards a provision regulating the records that should be kept when pipe was reconditioned and reused. In fact, in the years leading up to the initiation of the proceeding in which the Commission adopted GO 112, the Commission had circulated to California operators a staff proposal to impose pipeline safety regulation.[6] The staff proposal included a provision that provided: "No used pipe or pipe of unknown specification shall be used in a pipeline which is designed to operate at pressures of 300 psig or more." Subsequently, the Commission transmitted to the industry a revised staff draft that omitted the language that would have prohibited the use of reconditioned pipe or pipe of unknown specification. The Commission ultimately adopted a version of GO 112 that incorporated ASME B31.8-1958 without change, which permitted the use of reconditioned pipe and made no provision for keeping records specific to the use of reconditioned pipe. (ASME B31.1-1958, § 811.25.) As detailed in Chapter 3.C, even in a later era Commission staff reviewed and approved for filing several PG&E construction projects in which PG&E advised the Commission that it intended to use reconditioned pipe.

Had PG&E been aware of the condition of pup 1 and the other pups found in Segment 180, it would not have selected those pieces of pipe for use under any circumstances. To assert that a recordkeeping system for reconditioned pipe would have prevented the pups from being used in the Segment 180 project is both speculative and revisionist.[7] It has not been determined whether the pups were previously-used pipe. In hindsight, having a tracking system for the history of each piece of pipe used or in

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[5] When, in GO 112-C, the Commission adopted the federal standards it eliminated any reference to ASME B31.8 Code. See Dec. 78153 (adopting GO 112-C) (1970) (RH-30).

[6] Letter from John C. Morrissey, PG&E, to Public Utilities Commission, enclosing Comments on Staff's Draft of Proposed Gas Transmission Line General Order – PUC Study 1143, pp. 3-4 (April 9 1957).

[7] CPSD alleges, "If PG&E had kept orderly records of the purchase, installation, salvage, reconditioning, inspection, and reuse of pipe installed in its transmission system, PG&E would not have selected that piece of pipe [pup 1] for project GM 136471, because it did not meet PG&E's own specifications for high pressure transmission pipe." (Felts Report at 2.)

inventory would have been a desirable practice. However, that was not the practice in the industry in 1956, and it was not the policy choice the Commission made in 1960, despite an earlier staff proposal that would have barred the use of reconditioned pipe in higher pressure lines.[8]

Properly reconditioned pipe is as safe as new pipe. When reconditioning pipe, PG&E would have taken steps to ensure that the reconditioned pipe was safe and in good condition for reuse, including thoroughly inspecting the pipe, cutting out any portion of the pipe that contained dents or was otherwise not suitable for reuse, preparing the ends of the pipe to properly accept welds, and rewrapping the exterior to protect against external corrosion. New or reconditioned pipe installed after 1961 would have received a post-installation hydro test. Through PG&E's Pipeline Safety Enhancement Plan, over the next several years PG&E will either hydro test, replace, or confirm pipe specifications with verifiable documentation of all of the pipe in its transmission system. Through this newly-mandated process, PG&E will reconfirm the operational fitness of all of the pipe in its transmission system.[9]

2. PG&E's Records from the Construction of Segment 180

Relying on the same discussion from the Felts Report (section 2.1) that supports Violation 1, CPSD asserts that the quality of the existing construction records for Segment 180 falls short of a records standard it apparently reads into Section 451.[10]

PG&E acknowledges that the construction records it has located for Segment 180 do not contain documents or drawings that depict the Segment 180 installation in granular detail. However, as explained by

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[8] The AGA made this point last year when commenting on a PHMSA advanced notice of proposed rulemaking: "If any operator obtained information suggesting that substandard pipe had been installed, it certainly would remediate the situation. *The fact is that this type of information is very unlikely to exist in a company's written file or record*." (Emphasis added.)

[9] As discussed in Chapter 3.C, through its MAOP validation effort, PG&E is collecting and cataloguing information to identify reconditioned pipe in its system. PG&E expects that a catalog of reconditioned pipe that can be identified throughout PG&E's gas transmission system will be available at the conclusion of this effort, currently estimated to be completed by early 2013.

[10] Felts Supplement at 10, n. 21.

industry experts (James Howe in Chapter 1.B and John Zurcher in Chapter 3.A), the pipeline industry as a whole confronts challenges with respect to missing or incomplete records for pipelines installed over several decades. Pipeline regulators have recognized the reality that operators do not have comprehensive records going back 50 or more years, and reflected it in regulatory mandates and expectations. In addition to the less-rigorous industry practices that prevailed when Segment 180 and other vintage pipelines were installed, practical challenges with respect to document storage, relocation and inadvertent destruction or misplacement have contributed to the records gaps that PG&E and operators throughout the industry confront.

CPSD should not expect PG&E to have the detailed information regarding Segment 180 that forms the basis of its assertion. In 1956, when Segment 180 was installed, industry practice did not include creating construction drawings or other documentation that showed a pipeline installation at the joint-by-joint level. Nor was creating and retaining such construction documentation an industry standard or regulatory requirement – there were no regulations regarding construction records and the existing industry standard in 1956 did not provide for the detailed documentation CPSD asserts should be in the Segment 180 records. (ASA B31.1.8-1955.) Even today, the industry does not generally document pipeline installations at the joint-by-joint level for these small pipeline jobs. It is unrealistic to expect now (some 55 years after the fact) that construction documentation created at the time Segment 180 was installed would have tracked or depicted each pipe piece installed, each weld along the segment, or the presence of the pups that were involved in the Line 132 line break, or contained any other information that could have led PG&E to identify the pups.

CHAPTER 4B

POST-INSTALLATION PRESSURE TEST AND RECORDS FOR SEGMENT 180

CPSD alleges in Felts Violation 3 that PG&E's failure to locate and produce a record demonstrating a post-installation pressure test on Segment 180 constitutes a violation of Section 451 (from 1961 to 2010), ASME B31.8 (from 1955 to 2010), and Commission General Orders (GO) 112, 112A and 112B, § 107 (from 1961 to 1970).[11] This alleged violation is specifically based on PG&E's "failure to retain pressure test records for L-132, Segment 180."[12] PG&E has not located records showing that a post-installation pressure test was conducted on Segment 180.[13]

In 1956, when Segment 180 was installed, there were no federal or state regulations that required post-installation pressure tests on gas transmission pipelines. The industry used the recommended practices set forth in ASA B31.1.8-1955, but those practices did not have the force of requirements. Post-installation pressure testing was not required by state regulations until the adoption of GO 112 in December 1960 (effective July 1961), and not under federal regulations until 1970 following the passage of the Natural Gas Pipeline Safety Act of 1968. These regulatory events occurred years after the installation of Segment 180. Both the 1961 state regulation and the 1968 federal law exempted existing pipelines, including Segment 180, from pressure test requirements, applying the pressure test provisions only prospectively to newly-installed pipelines. (Chapter 1A.) In particular, the federal regulations, in 49 C.F.R. section 192.619(c), "grandfathered in" existing pipelines based on prior operating pressure history, and did not require that existing pipelines be pressure tested to establish the appropriate MAOP. In December 2003, when the new integrity management regulations were published, the Department of Transportation, Office of Pipeline Safety (OPS) chose not to adopt a proposal to require "once in a lifetime" pressure testing for existing pipelines, concluding that "[h]istorical safe operation, which in many cases involves several decades, provides confidence that latent defects will not result in pipeline failure as

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[11] Felts Supplement at 10.

[12] Felts Supplement at 10.

[13] As discussed in Chapter 3 of PG&E's testimony submitted on June 25, 2012 in the San Bruno OII (I.12-01-007), there is evidence that a pressure test was done on Segment 180 when it was installed.

long as operating conditions remain unchanged."[14] Following the San Bruno accident, the NTSB has recommended that PHMSA fundamentally rethink this position.[15]

In November 1955, in connection with the construction of Line 300, a large construction project involving many miles of new 34-inch backbone transmission pipeline, a PG&E engineer testified during an application hearing before the Commission that PG&E intended to hydrostatically test Line 300 in accordance with the 1955 ASA pressure pipe standard, was exploring the feasibility of conducting hydro tests in Class 2 locations, and planned to conduct such testing where practical.[16] During the process leading to the 1960 adoption of GO 112, PG&E stated (as did other California operators) that its practice was to use the B31.8 standard.[17] That PG&E used the ASA guidance does not alter the fact that the ASA standard was voluntary in 1956 when Segment 180 was constructed.

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[14] OPS stated: "RSPA/OPS has been convinced by the public comments, including discussion at the public meetings, that it is not necessary to require a once-in-a-lifetime pressure test to address the threat of material and construction defects. Historical safe operation, which in many cases involves several decades, provides confidence that latent defects will not result in pipeline failure as long as operating conditions remain unchanged." (https://www.federalregister.gov/articles/2003/12/15/03-30280/pipeline-safety-pipeline-integrity-management-in-high-consequence-areas-gas-transmission-pipelines#p-175.)

[15] Specifically, the NTSB recommended that PHMSA: "Amend Title 49 *Code of Federal Regulations* Part 192 of the Federal pipeline safety regulations so that manufacturing- and construction-related defects can only be considered stable if a gas pipeline has been subjected to a post-construction hydrostatic pressure test of at least 1.25 times the maximum allowable operating pressure. (NTSB Recommendation P-11-15)."

[16] Transcript of Record, Third Supplemental Application No. 29548 (P3-00006).

[17] Statement of PG&E, Investigation into the Need of a General Order Governing Design, Construction, Testing, Maintenance and Operation of Gas Transmission Pipeline Systems, Case No. 6352 (March 28, 1960).

CHAPTER 4C

Records Used by PG&E to Establish MAOP for Line 132

CPSD alleges that PG&E violated Section 451 and ASME B31.8 from 1977 to 2010 by failing to have adequate records to substantiate the MAOP of 400 psig on Line 132.[18] Contrary to these allegations, records maintained in PG&E's MAOP Binders demonstrate that PG&E properly established the MAOP of Line 132 pursuant to 49 C.F.R. § 192.619(c), and retained records supporting this pressure. As explained in detail below, PG&E's actions in 2003 corrected a prior misunderstanding about the MAOP, and did not result in an uprating of the line.

In the early 1970s, the CPUC revised its rules regarding gas system requirements (GO 112-C) to add a new requirement that transmission pipeline operators establish the MAOP for all transmission pipelines pursuant to 49 C.F.R. § 192.619. Under this code section, an operator was allowed to establish MAOP (in addition to other methods) by identifying the highest pressure experienced in the pipeline between July 1, 1965 and July 1, 1970 (Five Year Period). This code section (49 C.F.R. § 192.619(c)) has been referred to as the "grandfather clause."

In response to the new requirement, PG&E's Gas System Design Department undertook an effort to verify and record the MAOP for PG&E's natural gas pipelines operating at or above 20 percent of specified minimum yield strength (SMYS) in service at that time (1973-1975). To document this effort, a Gas System Design Department engineer prepared a spreadsheet for each transmission line. On each spreadsheet, the engineer identified the "old" MAOP at which the line or line section had been operating (often established by prior pressure tests). The engineer then turned to identifying the pipeline MAOP as determined by the newly-issued regulations. For many pipelines, the engineer was able to identify pressure test records that established MAOP pursuant to 49 C.F.R. § 192.619(a). For pipelines where pressure test records were not available, the engineer reviewed data previously compiled by the Gas System Design Department, and also asked field personnel from the thirteen divisions and Pipeline Operations group to provide pressure charts and terminal operating logs. Using these records, the engineer listed the highest pressure each segment had experienced during the Five Year

[18] Felts Supplement at 10.

Period, the date and location that pressure was recorded, and the division responsible for that section of the pipeline.

In the few instances where no pressure chart or operating log was available in this era, a signed statement from a division engineer or operator attesting to the highest pressure experienced during the Five Year Period was used to establish MAOP. This practice was one of last resort, and was used for a very limited number of pipeline segments. While changes in how PG&E has defined "segments" between 1974 and the present day prevent an exact calculation, PG&E's understanding is that the Gas System Design Department located a pressure chart or operating log establishing the MAOP for more than 90 percent of the grandfathered pipeline sections. The use of signed statements was the exception.

Mr. Gawronski incorrectly states that PG&E originally used the signed statement process in the 1973-75 effort to establish the MAOP for between 50 and 70 percent of its high consequence area pipe operated pursuant to the grandfather clause.[19] Mr. Gawronski's statement misinterprets PG&E testimony regarding PG&E's 2011 MAOP validation effort. As reflected in its testimony, PG&E has undertaken an MAOP validation effort pursuant to the Commission's Order Instituting Rulemaking to gather pipeline strength test records, pipe specification data, and highest operating pressure during the Five Year Period. At the time of the March 15, 2011 filing, PG&E's search for operating pressure records from 1965-1970 revealed that many of the underlying records that had been reviewed in 1973-1975 for grandfathered pipelines were no longer available. In these instances, the MAOP validation effort looked to the entry on the 1973-1975 spreadsheets for evidence of the highest pressure, characterizing the spreadsheet as a whole as a signed statement or affidavit. Therefore, while between 50 and 70 percent of high consequence area pipeline with an MAOP established under the grandfather clause lacked original high pressure records in 2011, almost all of these pipe segments had their MAOP originally established through pressure charts or terminal operating logs.

The MAOP for Line 132 was established using the highest pressure recorded on the line during the Five Year Period. During the Five Year Period (as it is today), Line 132 was operated in two distinct sections. Between mile points 0.00 and 46.59 (from Milpitas Terminal to Martin Station), Line 132 operated at pressures up to 400

[19] Direct Testimony of John Gawronski on behalf of the City and County of San Francisco, April 30, 2012, pp. 8-9.

psig. Between mile points 46.59 (Martin Station) and the end of the line at the San Francisco Division Gas Load Center, Line 132 was operated at pressures up to 145 psig. This was reflected on the original spreadsheet for Line 132 (PG&E's Supplemental Response to Legal Division Request 30, Question 30, Attachment 2, p. 102.) by dividing Line 132 into two entries, as denoted by the number to the left of the designation column. While PG&E has not located the "GC Chart" (which likely refers to a pinwheel-type pressure chart) identified on the spreadsheet, PG&E has retained operating pressure logs reflecting the 400 psig pressure during this period in its MAOP binders.

In 1978, the San Francisco Division provided information that might appear to show that the highest pressure actually measured and observed on Line 132 between mile points 35.84 and 46.59 during the Five Year Period was only 390 psig. However, the San Francisco Division information does not contradict the 400 psig high pressure for Line 132 between Milpitas Terminal and Martin Station. An explanation of the operation of the gas system, pressure measurement locations, and the boundaries of the San Francisco and San Jose Divisions may be helpful in understanding the reason that the San Francisco information did not reflect an actual pressure observation on Line 132.

In 1970, PG&E's gas system was centrally operated by Gas Control in San Francisco, and was also locally operated by four Terminals (Antioch, Brentwood, Kettleman, and Milpitas) and nine Division Gas Load Centers (Marysville, Eureka, Sacramento, Stockton, Fresno, San Rafael, Oakland, San Jose, and San Francisco). Pressures in the gas system were monitored and recorded continuously and logged at least hourly in these locations. PG&E's policy in 1970 was to keep the recordings and log sheets for at least five years. (PG&E's Supplemental Response to Legal Division Request 30, Question 30, Attachment 2, pp. 5-6.) For Line 132, pressure charts and operating logs were recorded at the Milpitas Terminal (mile point 0.00) and San Francisco Gas Load Center.[20] Pressure readings from the Milpitas Terminal were therefore the only source of information for pressures

[20] PG&E notes that the 1978 Letter from the San Francisco Division referred to in the following paragraph suggests that PG&E had pressure records at Martin Station (Mile Point 46.59) that measured pressure on the downstream section of pipe from that station. However, a pressure reading at this location does not bear upon the Five Year Period pressure for the section of Line 132 from mile point 0.00 to 45.69.

experienced during the Five Year Period for the section of pipeline operated to 400 psig (mile points 0.00 to 46.59).

CPSD relies upon the 1978 letter from the San Francisco Division for the conclusion that PG&E "sectionalized" Line 132 into one part with a 400 psig MAOP between mile point 0.00 and 35.84, and one part with a 390 psig MAOP between mile points 35.84 and 46.59. A data sheet attached to the letter purports to amend the MAOP of Line 132 "Upstream Martin Station M.P. 35.84 to 46.59" to 390 psig. However, the attachment identifies the Milpitas Terminal as the location where the pressure reading was taken. Thus, the San Francisco Division letter did not contradict prior research into historic operating pressures on Line 132, but instead only shows that the San Francisco Division did not review other pressure charts from the Milpitas Terminal, such as those from October 16 and 28, 1968, that indicate a high pressure reading of 400 psig. (PG&E's Supplemental Response to Legal Division Request 30, Question 30, Attachment 2 pp. 106-107.) The reference to mile point 35.84 reflects the mile point at which the San Francisco Division's responsibility for Line 132 began, rather than a pressure measurement location. A map of the Division boundaries, circa 1979, is included in PG&E's Supplemental Response to Legal Division Request 30, Question 30, Attachment 2 at 46.

During a records review in 2003, PG&E employees recognized that the 1978 amendment to Line 132's MAOP was in error, as the document upon which the amendment was based did not contradict other records previously used to substantiate the 400 psig MAOP. Consistent with the grandfather clause, PG&E amended the MAOP of Line 132 to accurately reflect that, based on records of pressures experienced during the Five Year Period, the MAOP between mile points 0.00 and 46.59 was 400 psig.[21] This record correction did not constitute an uprating under 49 C.F.R. part 192, subpart K in form or substance. Here, the records used to establish the highest operating pressure experienced during the Five Year Period established a 400 psig MAOP for Line 132 from mile points 0.00 to 45.69. PG&E's record correction did not establish a new, higher pressure for Line

[21] Appendix 1 to the Revised Report and Testimony of Margaret Felts contains various documents that relate in some way to the Line 132 MAOP. The appendix merely provides a series of illustrations of PG&E's misunderstanding regarding pressure readings that were originally used to establish MAOP during the Five Year Period, as well as the correction in 2003.

132, but instead amended its records to reflect the true MAOP allowed by the grandfather clause. While PG&E’s documents listing pipeline MAOP between 1978 and 2003 may have purported to limit pressure in this section to 390 psig, PG&E did not maintain any pressure limiting equipment at mile point 35.84 that could serve to limit downstream pressure to the lower value. Thus, when PG&E amended its records in 2003, there was no change in conditions along the line.

CHAPTER 4D

MILPITAS TERMINAL ON SEPTEMBER 9, 2010

CPSD alleges several violations in connection with the events on September 9, 2010 at Milpitas Terminal. CPSD asserts in Felts Violation 5 that PG&E violated Section 451 (in 2010) for failing to follow its internal work procedure regarding gas system clearance documentation. In Violation 6, CPSD alleges a violation of Section 451 (from 1991 to 2010) based CPSD's conclusion that the O&MI manual at Milpitas Terminal on September 9, 2010 was out of date by 19 years. CPSD asserts in Felts Violation 7 that PG&E violated Section 451 (from 2008 to 2010) because the operating drawing and SCADA display for Milpitas Terminal were purportedly inaccurate. Lastly, in Felts Violation 8, CPSD contends that PG&E violated Section 451 (from 1991 to 2010) due to the absence of certain back-up software at Milpitas Terminal on September 9, 2010.

1. Alleged Failure to Follow Clearance Work Procedure

a. The September 9, 2010 Clearance for Milpitas Terminal

PG&E acknowledges that the written clearance application prepared for the electrical work at Milpitas Terminal for September 9, 2010, did not designate a clearance supervisor or fully describe the work to be performed and the sequence of operations that would be undertaken. However, the field crew and gas system operators did follow good communication practices and took actions that focused on and furthered the safety of the work.

Prior to beginning work, the crew at Milpitas Terminal conducted pre-work meetings (tailboards) on September 9, 2010, at which they addressed safety issues, discussed the day's project, and outlined the steps they would follow.[22] The field crew and Gas Control also communicated throughout the process. At 2:46 p.m., the lead gas control technician called Gas Control to alert them that the clearance work was beginning. As the work progressed, the gas control technician called Gas Control several more times. (Transcript of Gas Control Log, September 9, 2010 (Ex. 4-3).) The purpose of these calls

[22] In addition, a pre-construction meeting was held in August in preparation for the project.

was to alert the gas system operators, prior to disconnecting the designated electrical equipment, that they were about to take a step that could affect Gas Control's ability to monitor the system at Milpitas Terminal. These clearance communications ensured that both the field crew and the gas system operators were aware that intermittent SCADA interruptions could occur as part of the process.

The field crew also took precautions when the steps they were taking on the project could potentially impact Gas Control's ability to control the system at Milpitas Terminal. Prior to moving the connections for the Genius Blocks[23] from the existing electrical panel to temporary UPS device, the lead gas transmission technician switched the valve controllers into manual, after documenting the pressures at each controller. While it was not expected that disconnecting power to the Genius Blocks would impact the valve controllers,[24] the crew put the controllers into manual as an added precaution. Once the Genius Blocks were reconnected to the temporary UPS device, the gas transmission technician and the contract engineer put the controllers back into automatic and rechecked the pressures at each controller to confirm they were functioning properly and that no pressure impact had occurred. While these precautions were not detailed in the written clearance, they were communicated to Gas Control prior to and after the actions were complete. (Ex. 4-3.)

[23] A Genius Block is a brand name for the input/output device for the PLC, which allows interface between the PLC and field devices, such as process transmitters (as inputs), and solenoids and valve actuators (as outputs, i.e., commands from the PLC).

[24] The valve controllers had previously been connected to temporary UPS devices in April 2010.

When the crew had completed all the steps in the electrical work they planned for the day the control system at Milpitas Terminal was functioning and no problems were occurring.[25]

Thus, while the written clearance documentation prepared for the September 9, 2010, work at Milpitas Terminal fell short of PG&E's clearance procedure, the field crew did take affirmative steps during the work to keep Gas Control informed of the status and potential impacts of the work, in order to minimize the likelihood that any adverse consequences could occur during the clearance. Although an unplanned pressure increase occurred, both CPSD and the NTSB concluded the pressure limiting system functioned as designed, and that a non-defective pipe would not have ruptured from the pressure increase that occurred. (CPSD Report at 8; NTSB Final Report, August 30, 2011 at 12.)

b. PG&E's Actions to Revise the Clearance Procedure

To improve the clearance procedure and ensure compliance with it, PG&E is revising its gas clearance procedure and implementing additional tools and training, as described below.

PG&E recognizes the importance of requiring a well-analyzed, fully and properly completed clearance form including risk assessment and contingency planning for all work that could potentially impact the gas system. Work that has been identified as potentially impacting a station (or valve) control system or electrical supply must be routed to the local facility/controls engineer for review to ensure the identified work will not pose a risk to the normal operations of the facility. Gas Control's final approval process verifies that all work associated with control systems or electrical supplies has been properly reviewed and if not, Gas Control routes the draft clearance to proper reviewers before issuing final approval.

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[25] When power supplies PS-A and PS-B experienced voltage fluctuations, the pressure transmitters powered by PS-A and PS-B sent invalid pressure readings to the valve controllers to which they were connected. Having received zero or negative pressure readings from the pressure transmitters, the controllers commanded their respective regulator valves open, as designed, which resulted in the unplanned pressure increase.

PG&E has also clarified and underscored the following in its revised clearance procedure:

- All sections and fields contained in the clearance form must be filled out completely. PG&E is building an electronic platform that will prevent the clearance form from moving forward for approval if it is incomplete.
- Individuals assigned the clearance supervisor role must have complete knowledge of the intended work and written clearance procedure before accepting this role.
- Field crew and control room operators must have clear and complete understanding of the scope and details of the clearance. The understanding of the clearance will be gained through a crew tailboard and discussions with the control room.
- Web-based training will be completed by all employees involved in the gas clearance process upon rollout of the revised procedure.

PG&E's Control Room Management process includes a change management procedure that requires commissioning and functional check out testing (end to end testing) of all components at the field level connected to SCADA. Commissioning and functional check-out testing is now being completed for all new and rebuilt installations in conjunction with work clearance activities. The requirement to write the step-by-step test sequence forces the engineering, field and Gas Control crews to proactively review the impact of potential equipment failure. These activities are additional measures PG&E is taking to ensure that facility equipment is capable of meeting normal operating requirements at all times.

Through industry benchmarking (site visits to more than a dozen major North American gas and electric utilities), PG&E has learned that the best in practice clearance processes utilize an electronic platform that is accessible to all participants involved in a clearance. Use of the electronic platform will ensure sustained conformance with the clearance procedure requirements and the completion of appropriate levels of review by engineering, maintenance, and Gas Control before clearance work begins. PG&E has committed funding to build the electronic clearance writing, calendaring, routing and approval platform, which will also allow enhanced Control Room visibility through the use of large video wall screens.

PG&E plans to further improve its clearance work processes by creating a Distribution Control Center. The Distribution Control Center will oversee a uniform distribution clearance process nearly identical to the transmission process. PG&E's Utility Performance Improvement team (Lean Six Sigma experts) in conjunction with Gas Control, engineering, and field maintenance has undertaken the effort to write the distribution clearance process.

2. Milpitas Terminal Operations & Maintenance Instructions Manual

CPSD asserts that PG&E violated Section 451 (from 1991 to 2010) because the O&MI manual at Milpitas Terminal was purportedly out of date on September 9, 2010. CPSD alleges, "The Operating and Maintenance Instructions manual at the Milpitas Terminal was out of date on September 9, 2010, possibly by as much as 19 years, which would make it a useless reference when the emergency occurred."[26]

CPSD quotes a portion of PG&E's Supplemental Response to Records OII Data Request 1-Q1b to reach the conclusion that "PG&E states that it does not know whether the latest Operating and Maintenance (O&M) Instructions manual was at the Milpitas Terminal on September 9, 2010 and is unable to verify what version of the manual was there." However, in its data request response, PG&E was addressing 11 major transmission stations; it was not specifically addressing Milpitas Terminal (or any particular station). Thus, when PG&E stated "[i]t is not possible to ascertain whether the version [of the O&MI] contained at a station as of July/August 2011 was the exact version that existed on September 9, 2010[,]" PG&E was talking about multiple stations generally, not Milpitas Terminal in particular. The import of the statement was not that the O&MI manuals at those 11 stations were out-of-date on September 9, 2010, but that in July/August 2011, nearly a year later, PG&E could not conclusively

[26] Felts Report at 8.

determine that the then-current version of the respective O&MI manuals were at each of the 11 stations on September 9, 2010.

CPSD submitted a follow-up question to PG&E that is not addressed in the Felts Report. In Records OII Data Request 30-Q9, CPSD asked specifically about the O&MI manual at Milpitas Terminal, inquiring, "Was there a hard copy version of the most recent Operating and Maintenance instructions at the Milpitas Terminal ("Terminal") on September 9, 2010?" PG&E responded – "Yes" - the then-current version of the O&MI manual was at Milpitas Terminal on September 9, 2010.

CPSD appears to have reached the conclusion that the O&MI manual at Milpitas Terminal was out of date by 19 years by misinterpreting another PG&E data response. In response to Records OII Data Request 1-Q7, dated August 1, 2011, PG&E provided CPSD with a "Summary Inventory" of the documents located at Milpitas Terminal as of August 2011. One entry on that 12 page inventory stated, "O&MI Instructions for Milpitas Terminal (Issued 1991, January 2011 update)." In discussing the alleged violation, CPSD states that PG&E "listed a 1991 manual in a Summary Inventory of Milpitas documents."[27]

CPSD apparently concluded from this entry in the Summary Inventory that the version of the O&MI manual at Milpitas Terminal on September 9, 2010, was the original 1991 O&MI manual. However, the entry in the Summary Inventory regarding to the O&MI manual – "Issued 1991, January 2011 update" – referenced the most recent version of the Milpitas Terminal O&MI manual, which was first issued in 1991 and updated in January 2011. PG&E provided a copy of this version of the Milpitas Terminal O&MI manual in response to Records OII Data Request 1-Q1b and its supplements.

3. Milpitas Operating Diagram and SCADA Display

CPSD alleges that PG&E violated Section 451 (from 2008 to 2010) and PG&E's "internal policies requiring retention of [engineering] records" (from 2008 to 2010) because "PG&E personnel at the Milpitas Terminal may have

[27] Felts Report at 8.

been working with an outdated map and [gas] control room personnel may have been working with an incomplete diagram of the Milpitas terminal."[28]

a. Operating Diagram

With respect to the Milpitas Terminal operating diagram (Drawing #383510), CPSD states, "In response to a data request, PG&E verified that drawing #383510, which it submitted to the NTSB, had been corrected after September 9, 2010 to accurately reflect the terminal design on that date. Thus, the diagram available to the personnel at Milpitas Terminal on September 9, 2010 did not accurately reflect the then current terminal design."[29]

PG&E acknowledges that it updated the operating diagram of Milpitas Terminal after September 9, 2010. However, the Milpitas Terminal operating diagram was updated either to reflect operational changes made following the events on September 9, 2010, or to correct information not related to the events on September 9, 2010, and that was not relevant to the crew's actions at Milpitas Terminal to address the pressure increase or electrical problems. The operating diagram was updated as follows:

- November 2010 – The depiction of valves V31, V47, V49, and V65 was revised from normally open to normally closed; the maximum operating pressure (MOP) values for Line 109 and Line 132 were revised from 375 psig to 300 psig. These revisions were made to reflect the actual MOPs and the valve positions following the pressure reductions implemented at the direction of the Commission after the events on September 9, 2010. The MAOP of Line 100 was corrected from 375 psig to 400 psig.
- January 2011 – PG&E corrected block valve number from 167 to 169. This valve is located on the pig receiver for Line 100.
- July 2011 - PG&E corrected the valve and pipeline size on the cross-tie between Line 131 and Line 300A.

[28] CPSD does not explain in the Felts Report or Felts Supplement the basis for asserting that PG&E failed to comply with "internal policies requiring retention of [engineering] records" with respect to the Milpitas Terminal operating diagram or SCADA diagram. (See Felts Report, § 2.5.)

[29] Felts Report at 9.

The operating diagram as it existed on September 9, 2010, contained the information necessary for the crew at Milpitas Terminal to fully respond to the unplanned pressure increase. The operating diagram accurately reflected the regulation and monitor valves that controlled pressure on the outgoing Peninsula pipelines, which were the central focus of the gas control technician as he worked with gas system operators to address the situation.

b. SCADA Display

With respect to the SCADA display of Milpitas Terminal viewed by the gas system operators, CPSD alleges, "[T]he diagram [display] for the Milpitas Terminal that was used by San Francisco Control Room operators was inaccurate and incomplete. The diagram has been revised three times since the San Bruno incident. On September 9, 2010 the diagram at the Control Room was apparently missing a bypass line outside of the Milpitas Terminal fence line. This appears to be a significant inaccuracy in the diagram because, during the emergency, PG&E personnel were attempting to control high-pressure gas that they thought might be by-passing the terminal."[30]

PG&E did revise the display of Milpitas Terminal that gas system operators view on the SCADA system after September 9, 2010. However, the SCADA display of Milpitas Terminal was revised only once, not three times, after September 9, 2010. PG&E's response to Records OII Data Request 8-Q8c, on which CPSD bases its assertion, stated:

> "Milpitas Terminal Operating Diagram – SCADA: On October 27, 2010, existing valves and piping related to the bypass system were added to the SCADA Milpitas Terminal operating diagram to provide Gas System Operators additional visibility of the bypass line configuration outside the Milpitas Terminal fence line. The valves that were added to the diagram were V-0.11, V-0.12, V-0.13, V-30, V-31, V-32, V-57.45, V-300, V-400, V-401, V-500, V-502.12A, V-600 and V-602, along with the associated piping. See attached snapshots of the

[30] Felts Report at 9.

SCADA Milpitas Terminal operating diagram before and after this revision. (Attachment 5)."

In addition, the SCADA display was not "missing a bypass line outside of the Milpitas Terminal fence line" and did not contain a "significant inaccuracy" as CPSD contends. (Felts Testimony, p. 9.) The bypass piping and valves at Milpitas Terminal that are used in daily operations, and that were in use on September 9, 2010, were reflected in the Milpitas Terminal SCADA display on September 9, 2010. The SCADA display as it existed on September 9, 2010 was provided to CPSD as Attachment 5 to PG&E's response to Records OII Data Request 8-Q8. Attachment 5 depicts the "station bypass" and valves 62 and 63 (the bypass line valves) at the right side of the diagram.[31]

The bypass piping and valves that were added to the Milpitas Terminal SCADA display on October 27, 2010, and which CPSD asserts were "missing" from the SCADA display, are part of an alternate station bypass system that is located outside the Milpitas Terminal, across a highway. The system was valved closed on September 9, 2010, as it normally is, thus the valves and piping that are a part of this station bypass were not involved in the events on September 9, 2010.

PG&E added this bypass system to the SCADA display for the following reason. Following the Line 132 rupture, PG&E engineers evaluated various methods PG&E could utilize to maintain a complete and reliable gas supply to the San Francisco Peninsula through the winter months. Among the options considered was potentially reconfiguring the outgoing pipelines from Milpitas Terminal to permit varying pressures among the lines, which may have required the use of the normally-unused bypass system. Anticipating the possibility that this alternate bypass system could come into daily use, PG&E engineers and Gas Control concluded that they should add this piping and valves to the SCADA display of Milpitas Terminal to enhance gas

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[31] CPSD erroneously cites to attachments 3 and 4 to PG&E's Response to Records OII Data Request 8-Q8 in its discussion of the Milpitas Terminal SCADA diagram. The attachments CPSD cited are Milpitas Terminal operating diagrams, not SCADA diagrams used by Gas Control. (Felts Supplement at 15, line 8, referencing footnotes 40-43; CPSD's response to PG&E Data Request 4-Q7.)

system operators' visibility with respect to the bypass configuration that would be temporarily in use.[32]

How much detail is shown on a given SCADA display is a matter of balance, with the objective being to provide gas system operators the key information they need to safely and reliably operate the system, but without creating the risk of data overload by including too much information. In most cases, only essential piping, valves and equipment are depicted. To include too much information could potentially obstruct gas operators from making accurate and timely operational decisions. For instance, there are hundreds of monitoring points at Milpitas Terminal associated with the valves and pressure control system. Including all of those data points on the SCADA display of Milpitas Terminal would so clog the display with detail that it would not be useful to the gas system operators, and would actually impede their ability to analyze and monitor the system. PG&E designed the SCADA display of Milpitas Terminal prior to September 9, 2010, to strike the appropriate balance, and made the decision to add the additional bypass detail after September 9, 2010, to achieve the same objective.

CPSD's assertion that the SCADA display resulted in confusion between the gas technician at Milpitas Terminal and the gas control operator regarding the valve numbers at Milpitas Terminal also is not correct.[33] The excerpts from the gas control telephone recordings on which CPSD relies do not support CPSD's conclusion. (See Felts Testimony, Ex. "Transcript_Excerpt_Bypass".)

The first conversation relied on by CPSD demonstrates that the gas system operators knew which valves control the bypass line that was in operation. The transcript says, "Okay, that genius block it reset everything in and opened up the bypass valve…. Oh no, not 62... Yeah." (Felts

[32] PG&E did not ultimately use this bypass system as part of the actions it took during the Fall of 2010 to ensure reliable gas delivery to the Peninsula.

[33] CPSD asserts, "Based on the San Francisco Control Room transcripts for September 9, 2010, it seems there was confusion between the person at the Milpitas Terminal and the Control Room Operator about valve numbers at the Milpitas Terminal. At least some of the confusion experienced at the Milpitas Terminal and the Control Room during the emergency appears to have been related to inadequate reference documents." (Felts Report at 9-10.)

"Transcript_Excerpt_Bypass" at 1.) Valve 62 is one of the valves on the Milpitas Terminal bypass line that is used in normal operations. (PG&E Response to Records OII Data Request 8-Q8, Attachment 5.)

CPSD has also misinterpreted the second conversation on which they rely. In that conversation, the PG&E gas system operator says, "Actually, well we can't see it. I don't know what opened up and what didn't. But every time I asked something, it looked like it opened up. Yeah. You know the station bypass apparently opened, valve 62, the mixer bypass, valve 29 opened. Our 300B was our primary support for the mixer and apparently those valves went open. Pretty much every time we asked him, he said it was opened." (Felts "Transcript_Excerpt_Bypass" at 1.) Again, the operator identified the bypass valve correctly. Moreover, when the gas operator says he "can't see it" – he is referring to the unreliable communications that occurred between Milpitas Terminal and Gas Control due to the power issues at Milpitas Terminal. The gas system operator was not saying that he could not see the station bypass line on the SCADA display.

4. Back-up Software at Milpitas Terminal

CPSD asserts in Violation 8 that PG&E violated Section 451 (from 1991 to 2010) because PG&E did not have back-up software for the valve controllers at Milpitas Terminal in contravention of PG&E's policy.[34]

CPSD's factual basis for the alleged violation is mistaken. CPSD states, "The first indication of a problem at the Milpitas Terminal was described by the PG&E maintenance personnel on site as a loss of controllers. He clarified the situation in a subsequent interview by stating that they lost the programming to 3 controllers."[35] CPSD does not cite to the interview or statements on which it relied to make this assertion.

While three controllers did experience programming issues on September 9, 2010, the problem with those three controllers was not the cause of or related to the unplanned pressure increase at Milpitas Terminal. When a controller of this type "fails" or loses power, the valve to which the controller is connected is automatically locked in its last position.

[34] Felts Report at 10.
[35] Felts Report at 11.

The power problems at Milpitas Terminal started with the unexpected failure of two 24v power supplies, PS-A and PS-B. The voltage output from these power supplies began to fluctuate, ranging from approximately 7v to 17v when measured by the crew during the troubleshooting they initiated after the problem became apparent. Power supplies PS-A and PS-B provided power to pressure transmitting devices, which send pressure readings to the valve controllers, which then act on that pressure data. When the voltage from power supplies PS-A and PS-B fluctuated, the pressure transmitters sent zero or negative pressure readings to the valve controllers, which then commanded their respective regulator valves open to compensate for the apparent lack of pressure in the pipeline. The fact that controllers commanded valves open demonstrates that they were working, and that they had not lost power or their programming when the pressure increase began.[36]

In addition to a mistaken factual basis, the PG&E "policy" on which CPSD bases this violation is inapplicable. CPSD bases this alleged violation on a quotation from the Milpitas Terminal O&MI manual that does not relate to valve controllers. The quoted "policy" addresses the Programmable Logic Controller (PLC) at Milpitas Terminal, which is not the same piece of equipment as the valve controllers CPSD is attempting to address.

CPSD states, "Despite PG&E's policy quoted below to have a back-up of the software onsite, there was no backup at Milpitas on September 9, 2010."[37] The "policy" to which CPSD is referring is from the Milpitas Terminal O&MI manual at pages 77-78:

> "The PLC system is located in the computer room in the Control Build.… […] The PLC may be accessed via programming terminal in the computer room or any PC with the GE VersaPro software. *Copies of the program are kept on the hard disk of the programming terminal*

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36 While it cannot be determined with certainty, PG&E believes the three controllers encountered problems during the time period in which the crew at Milpitas Terminal was troubleshooting the electrical system. In disconnecting and connecting wiring during the troubleshooting, the power was likely disconnected to the controllers, after which three of the controllers did not properly reboot when power was reconnected.

37 Felts Report at 10.

and the back-up copies of the programs must be kept on a floppy diskette at the Terminal. A hard copy is available at the terminal."[38] As the quoted passage makes clear, the "policy" CPSD relies on to allege a violation for the lack of valve controller software at Milpitas Terminal is actually addressing the programming for the PLC.

PG&E acknowledges that the gas technician at Milpitas Terminal on September 9, 2010, did not have the software[39] or cable connection he would have needed to reprogram the three valve controllers that experienced problems. That technician was headquartered out of Hollister station, but was covering Milpitas Terminal. Hollister station utilizes a different model of the same valve controller (Siemens 352 vs. Siemens 353), and the software and cable connections between the models are not interchangeable. PG&E recognizes the technician (and all field personnel) should be equipped with the appropriate tools.

However, as noted, the three controllers that experienced rebooting issues were not related to the pressure increase, thus restoring them even immediately would not have prevented or reduced the pressure increase at Milpitas Terminal on September 9, 2010. Additionally, even if the gas technician had had the ability to download the controller programming and connect his laptop to the controllers at Milpitas Terminal, the problem experienced by the three valve controllers was not a problem that the gas technician could have corrected. As CPSD stated in its report in the San Bruno OII, "The three controllers which had malfunctioned about the same time that the 24 volts was lost still did not work. It was after 10:30pm when the Sr. Gas Engineer was able to restore their operation. Those units suffered a rare type of malfunction and the manufacturer had to be contacted to advise how to correct it." (CPSD Report, January 12, 2012 at 88.)

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38 Felts Report at 10 (italics by CPSD).

39 The software the technician lacked was not the configuration programming for the valve controllers. That programming is available to field personnel on a shared drive. Rather, the gas technician did not have the necessary software on his laptop to download the configuration programming from his laptop to the Siemens 353 controllers.

CHAPTER 4E

SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA) SYSTEM

CPSD asserts that PG&E violated Section 451 (from 2008 to 2010) based on an allegedly "unsafe design of [its] Supervisory Control and Data Acquisition System."[40] At the outset, PG&E acknowledges that it can improve its SCADA system, and is taking steps to do exactly that. Those improvements are detailed below. However, with respect to the violation alleged here, PG&E does not agree that its SCADA system on September 9, 2010 was unsafe and constituted a violation of Section 451.[41]

1. SCADA and Gas Control on September 9, 2010

PG&E recognizes that the alarms that resulted from the power issues and pressure increase at Milpitas Terminal made it difficult for the gas system operators to respond to each alarm. Gas system operators receive and analyze SCADA data to monitor and control the transmission system. On September 9, 2010, operators were faced with analyzing a high volume of both reliable and unreliable data as the result of the power issues and pressure increase at Milpitas Terminal. The fact is that they could not and did not evaluate every alarm that they received. (As discussed below, alarm management is among the areas PG&E is addressing with respect to the SCADA system.)

Following the unexpected power issues at Milpitas Terminal, gas system operators knew that the SCADA information coming from Milpitas Terminal was mixed, some valid, some invalid. Operators trended the SCADA data at stations and monitoring points up and downstream from Milpitas Terminal to analyze what was happening and what responsive actions were required. Trending SCADA data up and downstream is the appropriate and effective method of analyzing the state of events on the gas transmission system, in both normal and abnormal operating situations. (Testimony of Thomas Miesner, filed on June 25, 2012 in I.12-01-007, Chapter 9.)

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[40] Felts Report at 11.

[41] CPSD does not explain the basis for asserting that this violation spanned from 2008 to 2010. (Felts at 11-12.)

Despite the volume of alarms and varied reliability of the data, prior to the rupture gas operators were aware of the pressure increase at Milpitas Terminal and acted to address it. Operators worked with the gas technician at Milpitas Terminal to troubleshoot the cause of the pressure increase and to control it. The gas system operators and the gas technician at Milpitas Terminal were aware that the monitor valves had been actuated to limit pressure on the Peninsula pipelines. As an additional protective measure, at 5:52 p.m., gas control lowered the pressure at upstream stations on the lines coming in to Milpitas Terminal to 370 psig. Gas control took this action because lowering the pressure upstream of Milpitas Terminal necessarily would lower the pressure downstream of Milpitas Terminal. Before that step could have significant effect, Line 132 ruptured at Segment 180, despite the fact that the pressure had not exceeded 386 psig at that location.

CPSD correctly points out that, immediately following the rupture, gas control operators did not initially respond to the low-low alarms at Martin Station that first came in at approximately 6:15 p.m.[42] As noted above, those low-low alarms were mixed together with many other alarms, some valid and some invalid, that had been occurring by that time for approximately an hour.

However, it is not correct, as CPSD alleges, that the gas system operators "did not recognize the drop in pressure until almost 30 minutes later, when someone from another location called in and asked them to look for the pressure drop on their SCADA screens."[43] The gas control recordings cited by CPSD ("Transcript_Excerpt_Martin_Low_Pressure") show that, at 6:27 p.m., 12 minutes after the first low pressure indication came in, gas system operators received a telephone call from Concord Dispatch relaying the report of flames in the San Bruno area. This was the first notice gas control had regarding the flames in San Bruno. At 6:29 p.m., 2 minutes after the initial call, and 14 minutes after the low pressure alarm, gas operators connected the low pressure alarm at Martin Station with the outside reports of flames to conclude that there was likely a line break in the

[42] Felts Report at 11.
[43] Felts Report at 12.

San Bruno area. (Transcript of Gas Control Log, September 9, 2010, (Ex. 4-3) ["We have a line break in San Bruno with flames. Sounds like a jet engine and Martin Station is dropping like a rock."].)

CPSD states, "On September 9, 2010, after controllers were lost and pressure went out of control at the Milpitas Station, many alarms went unacknowledged and repeated regularly, creating long screens of repeating alarms."[44] PG&E recognizes that alarm management in the SCADA system can be, and is being, improved. However, it is not correct that the valve "controllers were lost" or that valve controller failure was related to the pressure increase on September 9, 2010. (See Chapter 4.D.4 above.) Nor did pressure at Milpitas Station go "out of control." The redundant pressure limiting system (monitor valves) at Milpitas Terminal functioned as designed to control the pressure, which never reached the MAOP on Line 132 and did not exceed approximately 386 psig at the rupture site. (CPSD Report at 8, 24; NTSB Report at 12.)

CPSD also asserts, "In fact, even after they [the gas system operators] found the pressure drop, they could not identify the location of the pipe failure using SCADA data."[45] This statement is not accurate. As discussed above, the gas control recordings demonstrate that the operators had concluded, by 6:29 p.m., based on the SCADA data from Martin Station and reports of flames, that there had been a line break in San Bruno. (Ex. 4-3.)

CPSD asserts that the gas system operators did not know if there were valves on Line 132 that could isolate the rupture.[46] CPSD bases this assertion on the following quote from the gas control recordings: "I'm guessing there has to be some valves between Milpitas and [Martin] Station that Division will be operating."

However, the speaker who made the statement on which CPSD relies was not a gas system operator. The speaker was the off-duty Milpitas Terminal temporary supervisor who was called at home by a gas control operator to inform him of the current situation. The supervisor was observing that there would necessarily be valving that Division (Peninsula)

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[44] Felts Report at 11.
[45] Felts Report at 12.
[46] Felts Report at 12.

would need to do to reroute gas around the rupture in order to maintain gas supplies to the San Francisco Peninsula. The statement was not made by a gas control operator and was not related to knowledge about particular valves between Milpitas Terminal and Martin Station.

The only statement by a gas system operator from the cited exhibit that is related to the CPSD's assertion is when the gas system operator stated, in the same conversation, "I'm going to pull the map now."[47] This is a reasonable and understandable statement, and does not suggest that the gas operators "did not know if there were any valves that could be used to shut off the gas." Pulling maps and diagrams is fundamental to monitoring the gas system in both normal and abnormal situations. There are thousands of valves throughout PG&E's transmission system. Gas system operators have ready access to hard copy (and electronic) maps and diagrams that show every station and valve on the transmission lines between Milpitas Terminal and Martin Station. SCADA screens, diagrams and maps are necessary and valuable tools, as no operator could memorize where every individual valve is located on nearly 6,000 miles of transmission pipeline, nor could they safely take operational action based solely on memory.

2. PG&E's Actions to Improve its SCADA System

PG&E is implementing three significant projects that will expand the current SCADA capability to predict and proactively manage abnormal events on our transmission and distribution system. The three projects are:

- Automated Valve Program implementation
- OSIsoft PI Data Historian integration with SCADA and GIS
- Distribution Control Center creation

These projects are the foundation of the broad initiative PG&E has undertaken to build a comprehensive controls framework to move from monitoring and reactive, to predictive and proactive.

[47] Felts Report at 12, n.54 ("Transcript_Excerpt_Valves_Between_Stations").

a. Automated Valve Program

PG&E has embarked on an aggressive program to increase SCADA visibility and control capability on its transmission pipelines focusing on the most densely populated areas in our service territory. Upon completion of the Automated Valve Program, PG&E will have real-time knowledge of pipeline pressures at least every 5 to 8 miles on large diameter pipelines in Class 3 and 4 areas. The transmission automated valve field site installations include new pressure and flow data being transmitted to the SCADA system providing additional information that will be utilized by new SCADA control tools and technologies to provide PG&E's gas system operators with better situational awareness of pipeline conditions. The increased number of new field transmitters will result in a 100 percent increase from PG&E's current number of pressure transmitters connected to SCADA. PG&E will implement the Valve Automation Program in two phases. The table below shows the planned and completed installations of new pressure and flow monitoring visibility and valve control capabilities that PG&E will attain through the two phases of the Automated Valve Program:

TABLE 4E-1
PACIFIC GAS AND ELECTRIC COMPANY
VALVE AUTOMATION SCADA VISIBILITY/CAPABILITY

Valve Automation SCADA Visibility/Capability		Phase 1 (12/31/14)	Phase 2 (TBD)	Cumulative Total
New Transducers to increase visibility of pressure and flow condition on pipeline system via SCADA	Installed since 10/2010	100		
	Pressure Transducers to be installed	440	660	1100
	Flow Transducers to be installed	30		30
Automated Valve Installations allowing automated or remote shutdown capability of transmission pipeline in Class 3 and Class 4 locations	Installed since 10/2010	36		
	Total to be installed	220	330	550
Total Miles of Class 3 and Class 4 Pipeline with automated isolation capability	Active Fault Crossings	16		
	Mile of pipe	522	1260	1782

In addition to the Valve Automation Program, the Control Room Management Alarm Management initiative will allow this large increase in system monitoring points to be incorporated into the Gas Control function while at the same time managing alarms from these points in a manner which better pinpoints the cause of the alarms and allow gas controllers to focus their efforts on the highest priority safety-related conditions. Phase 1 Valve Automation work will additionally provide technology, tools, and training to allow our gas system controllers to make optimal use of the increased pressure and flow data and new automated isolation valves in an emergency. PG&E has contracted with a process and controls engineering vendor to implement new screens and tools using the OSIsoft PI Data Historian platform to aid gas controllers in detecting, analyzing and taking action to isolate the pipeline if a rupture or major leak event were to occur. These tools will package the operational information and data on a pipeline system to more clearly identify deviations from normal operations.

Each automated valve will be equipped with automatic and/or remote control capability designed to expedite the isolation of a section of pipeline. Each of these valve installation sites will send various alarm conditions to the SCADA system. Most importantly, an alarm indicating rapid pressure drop beyond the established threshold will be received by the SCADA system and annunciated in the control room.

PG&E will be investigating and pilot testing various available and in development leak detection, pipeline damage and ground movement technologies that could be tied to the SCADA system, providing real-time information and proactive identification of developing risks.

b. OSIsoft PI Data Historian Integration with SCADA and GIS

PG&E has been evaluating information technology solutions to deliver the right information to gas operators to allow them to make prompt, informed decisions related to pipeline safety. PG&E has begun work to integrate its OSIsoft PI Data Historian (described below), SCADA, and GIS systems to achieve an electronic platform designed to support the Control Room operators. PG&E is incorporating Lean Six Sigma improvement processes from a variety of internal stakeholders and industry consultants to ensure a solution focused on interoperability and usability. Examples include:

- PG&E has fully commissioned a new enterprise-wide OSIsoft PI Data Historian system that will be used to pull key relevant data together for operator and planning team use, and display material to operators on large screens in the control room. This platform will rapidly provide near real-time information to all areas of the Gas Operations organization, including engineering, planning, maintenance, and operations. This will provide better guidance and input for remote monitoring and controls, as well as for real-time operations.

- PG&E is using the new real-time OSIsoft PI Data Historian platform to support two large situational awareness screens. Billions of data records have been loaded into the OSIsoft PI Data Historian system representing more than a decade of historic SCADA information. New data is being added to the OSIsoft PI Data Historian system continuously, within seconds of being recorded in the SCADA system.
- In late December 2011, PG&E completed a SCADA enhancement that prioritizes alarms for appropriate operator action upon activation. This SCADA modification project provides PG&E's operating team the capability to filter alarms based on priority, data type, and geographic location. Alarm priorities can now be configured based on four categories: Emergency, High, Medium, and Low.
- On January 23, 2012, PG&E implemented a geographical based operating system for the consoles used by our gas system operators. Roles and responsibilities have been documented and individuals have been trained on the new geographical based north/south alignment. At any given time, operators are now responsible for monitoring the northern service territory or the southern service territory, not both. The completed human factors work (discussed below) and SCADA modifications contributed greatly to this effort.

In conjunction with the new alarm management strategy, PG&E has completed work with human factors consultants developing a new SCADA visual coding design, including use of color, text and symbols in graphic displays to present alarm status and data quality. The new design will meet the requirements of API 1165 (Graphic Standard, Recommended Practice for Pipeline SCADA Display).

PG&E is moving forward with plans to build a new control center complex to co-locate transmission, distribution, gas dispatch and emergency response organizations. PG&E has completed benchmarking activities; including site visits with more than a dozen major North American gas and electric utilities, and has begun the effort to select an external control room design consultant that will work with its facilities architect team to build out the new facility.

c. Distribution Control Center Creation

PG&E is moving forward with plans to create a Distribution Control Center. Thousands of distribution pressure points and flow meters will be installed over multiple years and will increase the availability of equipment status data on SCADA. The expanded visibility and control capability of the distribution system will be increased from 300 pressure points currently to more than 6,500 pressure, flow, and control points.

Both the Transmission and Distribution Control Centers will be supported by a common SCADA system and the OSIsoft PI Data Historian system, an enhanced clearance process, and integration with the Gas Dispatch and Emergency Response organizations. PG&E's current SCADA system has been reviewed and will allow expansion to add several thousand monitoring and control points.

CHAPTER 4F
PG&E'S EMERGENCY RESPONSE

CPSD alleges that PG&E violated Public Utilities Code Section 451 from April 2010 to September 2010 because our emergency response plans were "too difficult to use."[48] The "too difficult to use" standard does not exist in either the applicable federal code requirements or GO 112-E. PG&E's Emergency Response procedures complied with all applicable regulations.

1. PG&E's Plans

At the time of the San Bruno rupture, we had in place a comprehensive emergency response plan to address gas transmission pipeline incidents. The response plan was comprised of three main sources of procedures, the Company-wide Gas Emergency Plan, the Division Emergency Plans, and the Gas Transmission & Distribution Emergency Plan Manual.[49] The Company-wide Plan and the Division Plans overlapped significantly in substance; a Division Plan contained the current Company-wide Plan, with additional Appendices containing tailored information at a field level, such as contacts and assigned responsibilities. The Gas T&D Emergency Plan Manual included, among other things, logistical information, contact lists and emergency checklists for use by transmission district field personnel responding to an emergency. The emergency response plans were designed to be implemented by personnel trained on their use, and, accordingly, contained significant portions devoted to training and assessment.

2. Applicable Regulations

The federal requirements regarding emergency response are set forth in 49 CFR § 192.615. Section 192.615 requires that each operator "shall establish written procedures to minimize the hazard resulting from a gas

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48 Felts Supplement at 11.

49 The Gas Transmission & Distribution Emergency Plan Manual issued on November 24, 2009 and in effect as of the San Bruno rupture was provided with PG&E's June 20, 2011 filing as Exhibit P3-30152. The response to Legal Division Data Request 1, Question 8, mistakenly attached a mislabeled version of that manual. Although the version was labeled as issued on November 24, 2009, it contained the prior version that was being replaced, which was called the Gas Transmission System Incident Response Plan.

pipeline emergency." The procedures must provide, "at a minimum," for certain items, including identification of events that require immediate action; communication and coordination with external emergency responders and public officials; prompt and effective response to an emergency; actions to protect people first, then property; emergency shutdown and pressure reduction; making safe any hazards; and safely restoring service. Additionally, operators are required to train appropriate personnel and review the training's effectiveness; review employee activities for effectiveness; and establish and maintain liaisons with appropriate external emergency responders and public officials. These requirements were adopted by GO 112-E.

3. CPSD's Reviews of PG&E's Emergency Plan Indicate Satisfaction with PG&E's Plan

The Commission regularly reviews our compliance with Section 192.615. The CPSD's Utility Safety Reliability Branch audits the gas emergency plan through its annual review cycle, and also conducts periodic audits of PG&E's divisions and districts.

In recent years, prior to the San Bruno accident, CPSD conducted audits reviewing our Section 192.615 procedures and did not identify potential violations. From March 2 to March 5, 2009, CPSD conducted an audit of our Operation, Maintenance and Emergency Plan.[50] In the audit, CPSD reviewed the emergency procedures per the individual subparts of Section 192.615 and found each of PG&E's corresponding procedures "Satisfactory."

The San Bruno pipeline accident occurred in the Peninsula Division. From August 9 to August 13, 2010, CPSD conducted an audit of the Peninsula Division.[51] This audit included a review of our Section 192.615

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[50] This audit has been made publicly available on the Commission website. See *2009 Audit of PG&E's Operations, Maintenance and Emergency Plans*, available at http://www.cpuc.ca.gov/PUC/events/110208_docs.htm. Attached as Appendix A is an excerpt from CPSD's audit report.

[51] This audit has also been made publicly available on the Commission's website. See *2010 audit of PG&E—Peninsula Division*, available at http://www.cpuc.ca.gov/PUC/events/110208_docs.htm. Attached as Appendix B is an excerpt from CPSD's audit report.

emergency procedures. CPSD found our procedures for the Peninsula Division "Satisfactory" for each of the specific provisions of Section 192.615. CPSD sent a summary of the results of the audit to us on September 24, 2010, after the San Bruno accident, and as noted, posted the entire audit report to its website.

The CPSD audits did not raise any objections or concerns regarding our emergency plan being "very complex," "difficult for personnel to implement," or "unwieldy," as Ms. Felts alleges.[52] The audits did not point to any other factors regarding the plans usability. Additionally, the audits noted that the plan was updated on a schedule in accordance with the regulatory requirements.

We have not been provided other guidance by the CPUC or by PHMSA regarding what standard we should follow for a plan to be deemed not "too difficult to use."

4. Allegation that Transcript from Control Room Demonstrated Confusion

CPSD alleges that the transcript of the audio recording of the San Francisco gas control room during the San Bruno emergency demonstrated "confusion about the emergency response plan."[53] CPSD bases its contention on the transcript excerpts it titles "Excerpt_ER_Confusion." These excerpts do not show that the control room operators were confused about how to implement the emergency plan. While CPSD contends that it was unclear from the emergency plan who was supposed to be in charge of response to the San Bruno emergency, the transcripts show that operators understood that Kirk Johnson was in charge as the incident commander of the Emergency Operations Center, the highest level response center. Additionally, the excerpts show that the operators understood what response centers needed to be opened and what the purposes for those centers were. While there was some interchange of the terms GRC (Gas Restoration Center) and PRC (Pipeline Restoration Center) that required explanation, the substitution was merely because the term GRC had changed to PRC;

52 Felts Report at 12, 15.
53 Felts Report at 13.

the operators and contacts understood what the GRC/PRC response center was and its purpose. The excerpts do not show confusion - they show unscripted communications during a time of intense activity, communications in which Gas Control is supporting the activation of the emergency response centers required under the emergency plan.

CHAPTER 4G
EXPERT REVIEW OF PG&E'S EMERGENCY RESPONSE PLAN

1. Qualifications

My name is David E. Bull. I am an Associate of Risk Management (ARM) and Manager, ViaData LP, publishers of WinDOT, *The Pipeline Safety Encyclopedia*. I have 37 years' experience in the natural gas pipeline industry conducting leak detection surveys, training programs for leak detection, first response, and regulatory compliance, as well as evaluation and development of operations, maintenance, and emergency manuals.

My current activities include reviewing and publishing compliance information for WinDOT, conducting regulatory compliance training programs, and consulting with pipeline operators on regulatory compliance. I am an Associate Staff member for the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Training and Qualifications (T&Q), and have been conducting classes for T&Q since 1977.

I am a member of the Gas Piping Technology Committee Guide for Gas Transmission and Distribution Piping Systems and serve as secretary for the Damage Prevention and Emergency Response Task Group. In 2006, I spent six months in Kuwait developing the KOC Pipeline Safety Regulations based on the Department of Transportation (DOT) format. In addition to developing the regulations, I completed a study on Safe Distances and Class Location and wrote Public Safety Awareness and Operator Qualification Plans.

I am a member of the Simple, Handy, Risk-based Integrity Management Plan (SHRIMP) development team. My experience also includes risk assessments and compliance reviews for over 75 gas utilities for AEGIS Insurance Services and membership on the Damage Prevention Quality Action Team (Dig Safely). I was also a Contributing Editor for Pipeline and Gas Technology Magazine writing the monthly Pipeline Safety Arena column.

My complete Curriculum Vitae is included as Appendix C.

2. Introduction

PG&E operates natural gas and electric transmission and distribution systems in California. Its service territory extends from Eureka to Bakersfield and from the Pacific Ocean to the Sierra Nevada area. It operates approximately 42,141 miles of natural gas distribution pipelines, 6,438 miles of natural gas transmission pipeline and serves 4.3 million natural gas customers.

PG&E is a public utility regulated by the CPUC and must comply with pipeline safety requirements found in CPUC General Order No. 112-E. This order adopts the DOT pipeline safety regulations at 49 C.F.R. Parts 190, 191, 192, 193, and 199.

On September 9, 2010 a 30-inch natural gas transmission pipeline operated by PG&E ruptured in San Bruno, California. This incident was investigated by the CPUC Consumer Protection and Safety Division (CPSD) and as part of the investigation CPSD reviewed the PG&E Emergency Plan.

My review was undertaken at the request of PG&E counsel to review the PG&E Emergency Plan in effect on September 9, 2010 and how it complied with federal pipeline safety regulation 49 C.F.R. § 192.615 as identified in the CPSD Revised Report and Testimony of Margaret Felts (I.11-02-016). Specifically, this report response to allegations in Section 2.8 of the Felts Report captioned: "Emergency Response Plans Too Difficult to Use."

Documents provided for this review included the Company-wide Emergency Plan (Company Plan), the Peninsula Division Emergency Plan, the Gas Transmission System Incident Response Plan (GT Response Plan), the Gas T&D Emergency Plan Manual (GT&D Manual), the CPSD Incident Investigation Report, and the Revised Report and Testimony of Margaret Felts (I.11-02-016). The versions reviewed of the Company Plan, Peninsula Plan, and GT Response Plan were provided to the Commission by PG&E in response to Data Request 1, Question 8 in this proceeding. The GT&D Manual, which succeeded the GT Response Plan on 11/24/09, was provided to the Commission as Exhibit P3-30152 in PG&E's June 20, 2012 filing in this proceeding. A complete list of documents used in this review can be found in Appendix D.

3. Review of PG&E Emergency Plan and Compliance with Federal Regulation 49 C.F.R. § 192.615

The DOT Pipeline and Hazardous Materials Safety Administration enforces the federal pipeline safety standards found in 49 C.F.R. Parts 190-199 and Part 40. The regulations in 49 C.F.R. Part 192 "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards" apply to gas transmission and distribution operators. These regulations are adopted by the CPUC in its General Order 112-E and PG&E must comply with those sections applicable to its operations.

The CPSD report makes numerous references to § 192.615, Emergency Plans. This regulation was instituted in Part 192 on August 19, 1970, when the federal regulations were first adopted. It has been amended three times to its present form. The complete regulation, in effect on September 9, 2010, is as follows:

§ 192.615 Emergency plans

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:

(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.

(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials.

(3) Prompt and effective response to a notice of each type of emergency, including the following:

(i) Gas detected inside or near a building.

(ii) Fire located near or directly involving a pipeline facility.

(iii) Explosion occurring near or directly involving a pipeline facility.

(iv) Natural disaster.

(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.

(5) Actions directed toward protecting people first and then property.

(6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.

(7) Making safe any actual or potential hazard to life or property.

(8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.

(9) Safely restoring any service outage.

(10) Beginning action under § 192.617, if applicable, as soon after the end of the emergency as possible.

(11) Actions required to be taken by a controller during an emergency in accordance with § 192.631.

(b) Each operator shall:

(1) Furnish its supervisors who are responsible for emergency action a copy of that portion of the latest edition of the emergency procedures established under paragraph (a) of this section as necessary for compliance with those procedures.

(2) Train the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

(3) Review employee activities to determine whether the procedures were effectively followed in each emergency.

(c) Each operator shall establish and maintain liaison with appropriate fire, police, and other public officials to:

(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency;

(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency;

(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials; and,

(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property.

49 C.F.R. § 192.615.

In addition to the federal regulations at 49 C.F.R. § 192.615, two other documents were used in reviewing the emergency plans, one created by PHMSA and one created by an industry group, the Gas Piping Technology Committee (GPTC).

PHMSA released its Operations and Maintenance Enforcement Guidance (Enforcement Guidance) as the result of a Freedom of Information Act request in the spring of 2010. This document contains Code Compliance Guidelines for various sections of Part 192, including § 192.615. This guidance describes compliance and inspection activities and was made available to federal inspectors and available to state agencies. The Enforcement Guidance document is guidance only and cannot be considered required regulatory material. However, it does detail specific items that would be inspected and considered as actions operators would take to maintain compliance with the regulations. The PG&E Plan meets the items in the Enforcement Guidance listed as "Guidance Material." (The Enforcement Guidance references the GPTC Guide, see next paragraph). The Enforcement Guidance for § 192.615 is included in Appendix E.

Also used in this review is the Gas Piping Technology Committee Guide for Gas Transmission and Distribution Piping Systems (GPTC Guide). This Guide contains information on how to comply with Part 191 and 192 regulations. It was first written in 1970 for the newly-promulgated pipeline regulations and has been in continual publication. The Guide is referenced in the PHMSA Enforcement Guidance as "industry guidance available" and it includes material for § 192.615. The complete Guide Material for § 192.615 is included in Appendix F.

4. Plan Organization and Compliance

On September 9, 2010, PG&E had a written, comprehensive plan in effect that met the requirements of § 192.615. The plan consisted of the Company-wide Emergency Plan (Company Plan), the Peninsula Division Emergency Plan, and the GT&D Emergency Plan Manual (GT&D Manual) (together the "Plan"). (I understand PG&E inadvertently provided a mislabeled, prior version of the GT&D Manual in response to Legal Division Data Request 1, Question 8, and that is the version referred to in Ms. Felts's testimony. That prior version was titled the Gas Transmission System Incident Response Plan (GT Response Plan). I considered the GT&D Manual in effect as of the San Bruno rupture for my review, although I considered the prior GT Response Plan when discussing Ms. Felts's specific comments regarding that version.)

The Company Plan is divided into six parts as follows:

- Part I, Basic Plan, outlines the responsibilities and procedures that PG&E must have in place to respond to gas emergencies, as required by GO 112-E.

- Part II, Gas Emergency Skill Assessment and Development Guide, is a tool to assess and develop emergency response skills of employees. There are individual packages for the various Departments and Business Units.
- Part III, Gas Emergency Quick Reference, is an extract of Part I and is intended to provide the emergency supervisor/on-call advisor with a quick reference to various documents and procedures, such as phone lists and local procedures.
- Part IV, Gas Emergency Checklist, contains checklists of specific actions to consider when responding to typical gas emergencies.
- Part V, Annual Procedural Training Aid, contains a PowerPoint based module template, a performance check package, and a job aid for the training coordinator.
- Part VI, Appendices, contain procedures and documents that are specific to the local operating department's gas emergency plan.

The Peninsula Division Plan includes the Company Plan and the Division-specific requirements listed in Part VI, Appendices. The GT&D Manual also fulfills the requirements of Part VI of the Company Plan by including Gas Transmission & Distribution-specific information.

I have reviewed the Gas Transmission & Distribution Emergency Plan Manual that was in effect on September 9, 2010, as well as the prior emergency plan manual specific to gas transmission and distribution, the Gas Transmission System Incident Response Plan. In the GT&D Manual, the layout was significantly re-structured, however the substantive elements of the GT Response Plan that show compliance with § 192.615 in conjunction with the Company Plan are still present. The GT&D Manual includes numerous checklists for Plan Activation and response actions. The Emergency Management Organization section describes job categories and functions when the plan is activated. The checklists for various types of emergencies from Part IV of the Company Plan are included. As part of the restructuring that created the GT&D Manual, the flow charts referenced in Ms. Felts's report were replaced with checklists and text descriptions.

The GT&D Manual fulfills the requirements of Section VI, Appendices of the Company Plan and in conjunction with the Company Plan meets the requirements of § 192.615.

The Company Plan is organized in a functional manner that follows the outline of § 192.615. Paragraph (a) of the regulation requires a written plan that includes specific procedures. The Company Plan is itself a written plan, and Part I, Basic Plan of the Company Plan meets the specific § 192.615(a) requirements. Paragraph (b) of the regulation requires that operators shall train their personnel on these procedures. Part II of the Plan covers training requirements and skill assessments and Section V includes material for the annual training. Part III is a quick reference of the Basic Plan. Part IV includes checklists covering various emergency situations and is a useful tool for trained personnel, describing actions to protect life and property. Paragraph (c) of the regulation requires liaison with outside agencies; this activity is included in Part VI of the manual, which provides contact lists and meeting schedules with external entities.

The Plan employs cross-references to other Company documents not included within the written plan, but available to personnel and intended to be used as reference or instructions for aspects of emergency response. For example in Part I, 5.81, Gas Detected In or Near a Building, the Company Plan references UO Standard C-S0434 (Gas Leak and Odor Response) and leak survey standard C-T&CS-S0350. Section 5.8.6 references Standards 459.1 and 459.32-1 for load curtailment. In Part III, Gas Emergency Quick Reference, Gas Detected In or Near a Building references Company Standard Practice 460.21-3 and 460.21-4 as the procedures to use.

Incorporating by reference is a common practice in the development and maintenance of manuals. The referenced procedures may be used in several sections of a manual or in several different manuals. This avoids repetition within a single manual and ensures that when the referenced standard is updated, it will be current in all manuals where it is referenced.

In summary, the Plan meets all the requirements of the federal regulations in § 192.615. Part 1, Basic Plan of the Company Plan meets all the required elements for a written emergency plan as defined in §

192.615(a) and required actions listed in § 192.615(b) and (c). It complies with the items listed in the PHMSA Enforcement Guidance and follows the compliance guidelines in the GPTC Guide for Emergency Plans. The Peninsula Division Emergency Plan and the GT&D Manual work in conjunction with the Company plan to support compliance. The Plan is organized in a functional manner such that trained employees are able to implement it.

5. Regulatory Approach to Required Manuals under Part 192

The only direct regulatory guidance operators have regarding organization or length of emergency plans is the text of the § 192.615 regulation and the Enforcement Guidance. These do not prescribe the organizational structure or length of an emergency plan, and therefore operators must develop a system that suits their needs.

PHMSA Enforcement Guidance regarding § 192.615(a) states:

- Core emergency plans are fine for the whole company; however, there must be site-specific information about area locations covered by the locally-applied emergency plan. §192.615(a)
- Cross references must be included in the emergency plan, if material in other manuals are to be used at the incident site (i.e. Safety Manuals, etc.). § 192.615(a).

The PG&E Plan follows this guidance. The Company Plan is a core plan, with site specific information provided by Part VI, the Appendices that make up the Division Plans. The Company Plan cross-references other materials to be used in response to an emergency.

Operators can also look for instruction from the comments made by the Office of Pipeline Safety (OPS) in Notice of Proposed Rulemakings (NPRM) amending § 192.615. The NPRM for Amendment 192-24, published in the Federal Register at 40 Fed. Reg. 13317, stated:

> OPS proposes to clarify each of the present paragraphs (a) through (d), in §192.615 by listing specific topics or measures which must be covered in each plan. This proposed listing is intended to give operators more specific guidance as to what is necessary for an adequate emergency plan under §192.615.

The proposal is, nonetheless, written in performance terms, just as the existing rule, rather than in detailed specifications. *Consequently, if the proposal is adopted, an operator would remain free to develop a plan that is best suited to its particular operation within the outline provided by §192.615.*

40 Fed Reg. 13317 (emphasis added).

Similarly, OPS stated in the same NPRM:

Section 192.615(a) now requires that an operator have procedures to respond to a gas pipeline emergency, but does not give further details for developing the necessary procedures. OPS realizes that it is impractical to prepare detailed procedures for all types of emergencies. The response required will vary depending on the information an operator initially receives, the type and location of pipeline facilities involved, system pressures, gas load requirements, time of day or year, and other operating variables.

Emergency response procedures must be flexible enough to permit variations at the scene to accommodate unexpected events. At the same time, OPS believes the existing requirement does not go far enough to assist operators in preparing useful procedures. Therefore, §192.615 would be amended to ensure that the procedures, at a minimum, cover certain essential items which are set forth hereinafter.

The proposed listing of items under §192.615(a) should not be viewed as inclusive of all procedures necessary for emergency responses. In fact, OPS encourages operators to include any additional procedures in their emergency plans which are relevant to their pipeline operating conditions.

The final rule following this NPRM amended the regulation to its present language after comments on the NPRM were considered. In the preamble explaining the final rule, OPS stated:

> In the final §192.615(a)(4), the word "ensuring," used in the Notice, has been omitted because, as commenters indicated, no written plan can necessarily "ensure" the availability of personnel and materials at the scene of an emergency. (41 Fed. Reg. 13586.)

The NPRM discussions and the final rule preamble speak to the federal decision to limit the specificity of the regulation to listing of procedures that must be addressed, and to allow operators to write their emergency response plans in the manner that best fits their operation.

Part of that flexibility is what operators decide to include directly in the plan. DOT has recognized the use of cross-reference for organization of manuals required under Part 192. In Amendment 192-71, Operation and Maintenance Procedures for Pipelines, 59 Fed. Reg. 6579, the Research and Special Programs Administration (RSPA) (now PHMSA),[54] amended § 192.605, Procedural manual for operations, maintenance, and emergencies. The first sentence of paragraph (a) of §192.605 states:

> (a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response.

When the final rule was issued, RSPA responded to NPRM comments as follows:

> <u>Comments on O&M Manuals</u> (Proposed §192.605(a)): Two industry associations and 15 operators recommended that RSPA not specify those written procedures that operators must keep in their O&M manual. Companies currently have Operation and Maintenance Manuals, Emergency Manuals, Plumber

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[54] RSPA was formerly the administration responsible for DOT pipeline safety regulations. It was reorganized and renamed in 2005 to the Pipeline and Hazardous Materials Safety Administration.

> Manuals, Leak Control Manuals, Corrosion Manuals and other manuals containing information vital to pipeline operation. Operators have, throughout the years, prepared manuals for their systems documenting procedures appropriate for the specific needs of that system. They stated that a requirement to combine these documents into a single volume would create an oversized, impractical and unwieldy manual.
>
> Response: RSPA did not intend the proposed O&M manual to be an unwieldy single volume, or binder. Although, as proposed, the final rule requires each operator to incorporate its O&M procedures for each pipeline system into a single manual, this manual may be a comprehensive set of cross-referenced volumes set up according to functional subjects. Operators are expected to maintain a complete set of the volumes of the comprehensive reference manual at one location. Copies of parts of the manual, containing the information pertinent to particular functions or facilities in a system, must also be kept wherever needed for field operations. We propose to consolidate and reorganize relevant procedures, existing in most cases, into a comprehensive reference for use by operating personnel. (59 Fed. Reg. 6580.)

The RSPA/PHMSA rulemaking discussions demonstrate the OPS philosophy that operators have the latitude to organize plans to suit the needs of their operations. The organization of PG&E's plan is functional for the needs of its multi-faceted operations and consistent with this OPS philosophy. The Company Plan is organized into Parts I to VI as described. The Basic Plan (Part I) covers the key elements personnel must understand and implement for emergency response. The Peninsula Division Plan includes the local information required under Part VI. The GT&D Manual is written to adhere to the Company Plan, and includes communication information, notification lists, personnel, maps, records, material, tools, equipment, operating instructions, and local agencies such as police and fire. Including this information increases the length of the Plan, however this material is needed to maintain compliance with § 192.615, as mentioned in the PHMSA guidance above.

The PG&E Plan meets the requirements of the regulation, and is consistent with the PHMSA Enforcement Guidance and PHMSA's approach to manual organization, which emphasizes flexibility so that operators can develop plans to suit their needs.

6. Industry Guidance and Practice

Through the Gas Piping Technology Committee Guide, industry has provided useful guidance for the structure and content of emergency plans. The GPTC Guide is written by a committee of approximately 100 pipeline industry professionals, who work to ensure the guidance follows the intent of the regulations. As a consensus document, the guidance for § 192.615 is a compilation of industry experience in methods to comply with this regulation. PHMSA's own reference to the GPTC Guide in its Enforcement Guidance, while not endorsing the Guide as approved compliance methods, indicates that PHMSA respects the guidance material's capacity to provide useful compliance actions.

The Guide addresses each paragraph of the regulation with guidance for compliance. For example for § 192.615(a), the requirement for a written plan, the Guide states:

1 WRITTEN EMERGENCY PROCEDURES (§ 192.615(a))

(a) Written procedures should state the purpose and objectives of the emergency plan and provide the basis for instructions to appropriate personnel. The objective of the plan should be to ensure that personnel who could be involved in an emergency are prepared to recognize and deal with the situation in an expeditious and safe manner.

(b) Establishing written procedures may require that parts of the plan be developed and maintained in coordination with local emergency response personnel (e.g., police, fire, and other public officials) and with other entities in or near the pipeline rights-of-way (e.g., other utilities, highway authorities, and railroads) that may need to respond to a pipeline emergency.

(c) Written procedures should also include instructions on interfacing with the Incident Command System (ICS) typically used by emergency responders. See 1.2 below for interfacing with an ICS and 1.10 below for general information about the ICS.

(d) To ensure the safety of the general public, written procedures should provide for the following as applicable.

The Company Plan, Peninsula Emergency Plan, and the GT&D Manual conform to these guidelines.

The PG&E Plan follows an organization and structure similar to that used by other operators within the pipeline industry. Operators provide detailed information on responding to emergencies and the listing of specific information relative to each area of operation. Operators with transmission, distribution, and control room operations must include information for all the operating divisions to react to local emergencies, and how to integrate all facets of operations into one response plan, entailing much documentation. PG&E's plan reflects these factors as well.

7. Allegation that Plan is Too Complex

All emergency plans used by natural gas operators contain detailed, specific information on communications and actions for trained personnel to implement. A person unfamiliar with the organization and text of an operator's emergency plan, and without the training, skills, and knowledge assessments required by the plan for emergency responders, may well be confused by the plan's layout and organization. RSPA made the following comment in Amendment 192-71, Operation and Maintenance Procedures for Pipelines, 59 Fed. Reg. 6579:

> "Response: The proposed rule was not written in specification, or how-to-do-it fashion. Rather, the proposed rule used performance language which would require that gas pipeline operators maintain O&M procedures on specific topics. We are providing a list of required items that must be included, but operators can determine how best to do so for their particular system,

> so long as it provides for safe maintenance and operations.
>
> Written procedures on those specific topics are essential to safe operation and maintenance of a pipeline. Procedures of a general nature provide little guidance when needed. *When used properly by trained personnel*, the specific procedures should have a positive effect on pipeline safety." (Emphasis added).

This quotation shows the philosophy of RSPA regarding manuals required under Part 192, that they provide information for trained personnel to use. These manuals include the training requirements and materials needed so that when employees are trained they have the knowledge, skills, and abilities to use the manuals for pipeline safety.

Under the Plan, PG&E personnel are provided training on how to implement the Plan. The GT&D Manual required personnel to have annual training. This training is further described in the Company Plan in Part I Section 2.7, Part II and in the training material presented in Part V. This training material reviews the Corporate Emergency Organization, Emergency Levels and activation of the various emergency centers.

PHMSA offers little guidance, as discussed, on how to organize an Emergency Plan and operators must develop a system that suits their needs. The PG&E Plan is generally organized in a functional manner following the outline of § 192.615 such that it could be implemented by trained PG&E personnel. As discussed, the Company Plan covers the requirements of all Paragraphs of § 192.615 (a) to (c). The Peninsula Emergency Plan and the GT&D Manual provide information required in Part VI of the Company Plan and are designed to be used in conjunction with the Company Plan.

PG&E has chosen to include all requirements into a master document. Other operators choose to maintain smaller documents with extensive cross references. The Company Plan is approximately 536 pages long, organized into Parts I to VI as described. However, Part 1, Basic Plan, which captures all the elements required for an emergency plan, is 51 pages long. Part II (Training) is 193 pages and Part V (Training) is 213 pages, together totaling

406 pages. These two parts could be moved from the Company Plan to their own “Required Emergency Plan Training” manual. This requires links or references to another document, and updates must be coordinated with any changes to the Emergency Plan. Including it in the overall document ensures all elements of a required emergency plan are maintained together.

Ms. Felts’s testimony includes diagrams from the GT Response Plan as examples to support the allegation that PG&E’s Plan was too difficult to use. These diagrams are labeled in the GT Response Plan as Attachment 1 - Gas Transmission Levels of Emergency and Attachment 2 – GT&D/GTM&C/Company Emergency Response Process (Ms. Felts labels them Figures 1 and 2). In Sections 5.0 through 6.4, the GT Response Plan explained a phased-in approach to activating additional levels of command, control, and communication centers, and included Attachments 1 and 2 as visual representations.

Comprehensive explanation of the activation processes captured in Attachments 1 and 2 is described in the Company Plan in Part 1, 3.0 Concept of Gas Emergency Operations. Section 3.0 provides the details of PG&E’s levels of emergencies, response actions for each level and the activation of Operations Centers to coordinate all actions related to the emergency. Section 3.3 has specific procedures and actions for personnel involved in a gas emergency. Each level of Emergency is defined and the criteria used to move the emergency to the next level are specified. As an example, a level 1 emergency involves a small number of customers. It can be handled within the local area. However, should the incident expand to involve a large number of customers or resources from outside the affected area, the event then becomes Level 2. At this level a gas transmission emergency (a GT&D emergency) would require the PRC to be activated. This would cause GT&D to transition to the ICS for emergency response and communications as shown in the attachments.

The Attachment 1 flow chart starts by describing each emergency level with the extent of the incident and resources needed to respond. A decision tree is used to determine if the incident should elevate to the next level and the type of response needed. Attachment 2 is a companion piece describing the lines of communication and additional centers that must be included as the incident level increases. Attachments 1 and 2 are graphical representation flow charts to guide trained personnel in this process. They visually display the decisions and actions trained personnel can use to evaluate an emergency situation and implement the phased-in approach to emergency management and organization. They permit personnel to quickly and easily follow the processes described in the manual and presented in training. As discussed above, RSPA/PHMSA has expressed that procedures in manuals required under Part 192 are intended for use by trained personnel.

It is my opinion that the allegation regarding the complexity of PG&E's emergency plan is not supported by a review of the Plan documents or the examples highlighted in Ms. Felts's report. The Company Plan sets forth a functional organization that follows § 192.615 and can be implemented by trained personnel. The Peninsula Division Emergency Plan acts as a required complement to the Company Plan by including specific information necessary for use by local personnel. The GT&D Manual similarly acted as a functional adjunct to the Company Plan. The prior GT Response Plan was also designed in a manner such that trained personnel could implement it, including through use of the visual representations for escalation of emergency response contained in Attachments 1 and 2.

8. Control Room Transcript Review

I reviewed a transcript from the San Francisco Control Room labeled as "confusing" in the Felts Report. It appears the personnel talking in the transcript were aware of personnel to contact (Trista Berkovitz) and that the Operations Emergency Center (OEC) would need to be opened, indicating a Level 4 emergency as shown in Attachments 1 and 2 (Figures 1 and 2 in Ms. Felts's report). Kirk Johnson is shown in the transcript identifying himself as the Emergency Operations Center (EOC) on call. Trista Berkovitz contacts the control room and is made aware that people are on site and the Gas System Operators (GSOs) are talking with those personnel.

Personnel taking part in these discussions were aware of whom to contact regarding the OEC (Trista Berkovitz) and the PRC (GRC) (Todd Hogenson). Mr. Johnson (through another) relays information regarding the opening of the EOC and OEC. The PRC in Walnut Creek is identified and a means of communication is established through cell phones.

Communications are being established with the appropriate personnel for activation of the emergency management organizations. The questions asked solicit information needed to establish communications. Information is obtained and relayed to others. The transcript does not show the gas controllers reacting from confusion, but rather reacting according to the Plan to establish communications with the emergency management organizations that are activated under Section 3.2 of the Company Plan, Company Emergency Management Organization. Additionally, it appears the Control Room communications are following the paths described in Attachments 1 and 2 to the GT Response Plan. The GT&D Manual, which would have been in effect at the time, includes sections on GRC Overview and Activation as Sections 2.5 and 2.6. Section 2.7 defines the EMO structure, responsibilities and the interaction of various levels of the Emergency Coordination Centers (OEC, PRC, etc.). The conversations in the Control Room transcript excerpt show personnel have knowledge of the emergency management organization structure set out in Section 2.7 and understand the need to contact personnel responsible.

9. Conclusions

It is my opinion the Company Wide Emergency Plan, Peninsula Emergency Plan, and the GT&D Manual meet the regulatory requirements of § 192.615. They satisfy the provisions in the PHMSA Enforcement Guidance, and follow the basic outline as described in the GPTC Guide. In addition, the GT Response Plan, in conjunction with the Company Plan, met the requirements of § 192.615 when it was in effect. The PG&E Plan is similar in design and organization to those of other pipeline operators. The Plan is written so that trained personnel can implement the procedures, using text, flowcharts, and checklists. For example, the figures highlighted in Ms. Felts’s report graphically represent the emergency levels and the communication paths as emergencies escalate in nature. They provide visual information for trained personnel to identify the next steps in the communication process.

The transcript that is labeled “confusing” does not indicate confusion in the Control Room. Personnel asked questions necessary to gather information about the emergency management organizations. Their questions were in line with the flow charts and checklists detailing who should be in the overall communication loop.

It is my opinion that PG&E’s Plan follows regulatory and industry guidelines and allows for trained personnel to understand and use the plan to respond to emergencies.