Docket No. SA-534

Exhibit No. 2-Q

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

SENIOR CONSULTING ENGINEER RMP-06
MEMO TO FILE AND SUPPORTING DOCUMENTS

(85 Pages)

tions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include, ASME/ANSI B31G; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-104, 72 FR 39012, July 17, 2007]

§192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) *Third party damage and outside force damage*—(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP-0502-2002 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage*. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV)*. If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

(e) *Plastic transmission pipeline*. An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following

Memorandum

Date: June 14, 2006 **File #:** RMP File 8.10

To: RMP File 8.10 (RMP-06 Risk Management Procedure)

From: Chih-Hung Lee

Subject: ASV & RCV Consideration Guideline

Pacific Gas and Electric Company

MEMO TO FILE:

The purpose of this memo is to document our review of Automatic Shut-off Valve (ASV) and Remote Control Valve (RCV) implementation and to provide guideline for when they are appropriate.

Introduction:

49 CFR 192.935 requires the development of additional preventive and mitigative measures including ASV or RCV. RMP-06 Section 7 "Continual Evaluation and Assessment" and Section 9 "Preventive and Mitigative Measures" also address the additional Prevention and Mitigation methods that the Company is taking to protect HCAs in accordance with 192.935. This document provides the review of ASV and RCV literature and establishes Company guidelines for consideration of ASV or RCV installation.

Background:

There are many industrial references regarding pipeline explosion, valve spacing, safety, Methane emissions, ASV vs. RCV and cost/benefit study. The following facts were found in these references (see the references list 1-8):

I. Released gas when pipeline ruptures:

1. Most of the damage occurs immediately (within 30 seconds) from the initial loss of containment. References 1, 3, 5 & 7.
2. The burst of energy is independent of valve location and valve operation conditions (open or close). References 5, 6 & 7.
3. The rate of methane released from the broken pipe decreases exponentially with time. The maximum thermal dosage is a function of the distance between valves and the average initial pressure. It is not uncommon for the gas to burn for an hour after the valves are closed. The duration of fire has (little or) nothing to do with human safety and property damage. References 5 & 7.
4. Leaks will not trigger ASV. References 3 & 7.
5. Leaks will continue for a long period of time (hours) regardless of valve location and valve operating condition. References 3 & 7.
6. For safety when there is a leak, the priority shall be:

   a. Evacuate people
   b. Prevent ignition
   c. Shut-in the system (valves)

II. Valve Spacing:

7. References (1 to 4; & 7) confirm valve spacing is an O&M issue and not safety decision.
8. Valve placement was primarily an economic matter rather than a safety consideration. The increase of number of valves required for higher population areas was based on minimizing the volume of gas release during maintenance activities not on public safety. References 1, 4 & 7.

III. Safety:

9. A review of the 1995 to 2004 gas incident reports showed 14 fatalities and 30 injuries, all related to ruptures (approximately 30 seconds). References 4 & 7.
10. ASVs will not provide additional safety to people or prevent property damage. The damage will happen before the ASV can have any effect on the ruptured pipeline location. References 4 & 7.
11. Preventing pipeline ruptures measures should be the top priority by using measures such as:
    a. Use New presumably tougher pipe, improved mill and construction inspections and an updated more durable coating.
    b. Prevention Technologies such as tape or other warning techniques, and most obvious.
    c. The periodic reassessment with the required IMP to address all the pipeline threats.
    d. Public Safety and Emergency training & drills
    e. USA
    f. Stand-by

IV. ASV vs. RCV

12. Reference 8 (PG&E's letter on Remote vs. Automatic Valves, January 12, 1996) summarizes the review of ACVs (ASVs) and RCVs. It strongly recommends using RCVs over ASVs, due to many reliability concerns on ASVs and our confidence of using RCVs in conjunction with SCADA.

Conclusion and Company Guidelines:

After reviewing all the facts, we conclude using ASV or RCV as a P&M in a HCA has little or no effect on increasing human safety or protecting properties. ASV or RCV may help reduce shutdown time and gas releases during repair which will reduce repair cost and improve system recovery. In comparing ASV and RCV, we prefer RCV over ASV due to many issues regarding RCV. Installation of ASV or RCV is a mitigative measure to minimize cost after a pipeline rupture. Our goal is to implement P&M that prevents pipeline failures. We will emphasize on preventive measures such as: using better material, prudent design and construction methods; monitoring systems, enhance the periodic reassessment with IMP to address all the pipeline threats. Enhance the Company USA and Stand by policies and implement public safety training and field drill to prevent and mitigate 3rd party damage. In conclusion, we adopt the following guidelines:

1. We do not recommend using ASV or RCV as a general mitigation measure in HCAs, however, for some specific conditions such as: bridge crossings, river crossings, earthquake fault crossings, etc. RCV may be installed for economic and operational reasons.
2. It is our policy to review by the unique attributes during the LTIMP process (RMP-06 Section 7.2). Each case shall be thoroughly reviewed before any RCV is installed.

Chih-Hung Lee
X4316

Cc: CMWarner
DJCurtis
WJManegold
EEMuse
JSVolkar

References:

1. Eiber, R.J. and McGehee, W.B., *Design Rationale for Valve Spacing, Structure Count, and Corridor Width*, PR249-9631, PRC International, May 30, 1997.
2. Shires, T.M. and Harrison, M.R., *Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implication for Today's Natural Gas Pipeline System*, GRI-98/0367.1, December 1998.
3. Sparks, C.R. et al., *Remote and Automatic Main Line Valve Technology Assessment, Appendix B*, GRI-95/0101, July 1995.
4. Sparks, C.R., Morrow, T.B. and Harrell, J.P., *Cost Benefit Study of Remote Controlled Main Line Valves*, GRI-98/0076, May 1998.
5. Harrison, M.R. and Cowgill, R.M., *Summary of Methane Emissions from the Natural Gas Industry*, Radian Corporation, Draft Report, January 1996, p. 45-51.
6. Texas Eastern Transmission Corp., *Natural Gas Pipeline Explosion and Fire*, NTSB/PAR-95/01.
7. Process Performance Improvement Consultants (P-PIC), White Paper on Equivalent Safety for Alternative Valve Spacing, Draft April 18, 2005
8. PG&E's letter on Remote vs. Automatic Valves, January 12, 1996

Catalog No. L41034e

Technology for Energy Pipelines

Design Rationale for Valve Spacing, Structure Count and Corridor Width

Contract PR-249-9631

Prepared for the
Design, Construction and Operations Committee

of
Pipeline Research Council International, Inc.

Prepared by the following Research Agencies:

Robert J. Eiber, Consultant Inc.

Authors:
Robert J. Eiber
Wes McGehee

Publication Date:
May 30, 1997

within a distance of a pipeline that could be a potential hazard for people inside the housing if it is subjected to rupture of a pipeline operating at 72% SMYS.

Rationale on Valve Operation

None of the codes reviewed in this study required the use of any specific type of valve closure mechanism. In a number of the codes, remote operation of the valve was mentioned as worthy of consideration. However, the type of valve closure was left to the operator.

Table 5. Summary of Building Exclusion Conditions
Proposed by U.K. HSE for BG Pipelines

Zone	Multiples of Building Proximity Distances in TD/1		
	0 - 1.5 (Inner Zone)	**1.5 - 3 (Middle Zone)**	**4 (Outer Zone)**
A. Domestic housing	Refuse	Consult	Allow
B. Factories	Allow (refer to BG inside one BPD)	Allow	Allow
C. Retail-type developments	Consult	Consult	Allow
D. Sensitive areas and developments	Refuse	Consult	Consult

GRI Study on Remote and Automatic Valves. A GRI study[12] was conducted to assess the state-of-the-art of remote and automatic main line valve technology for line break control in natural gas transmission systems. The abstract of this study is as follows:

"Present equipment in use by the natural gas industry for detection and control of pipeline breaks has proven unreliable for many applications. While the valves and their gas/hydraulic operators normally perform adequately, the detection systems and logic control used to trigger the closure of automatic valves are plagued by reliability problems. Most detectors seek to identify a rupture event by monitoring transient pressure signals that are generated in the pipeline by the quick release of gas. However, the allowable detection sensitivity of these devices is limited by other operational transients in the pipeline with characteristics similar to line breaks. In order to avoid false closures due to normal transients, detector system sensitivity must be severely reduced, in some cases, even to the point of inoperability on a full line break."

"Computer modeling can be used to predict the intensity of line break signals and other operational transients within the pipeline. This approach may enhance the reliability of line break detection by evaluating alternative sense parameters, and by identifying a threshold setting or trip level at each valve that best discriminates a line break from other pipeline transient conditions."

The Appendix to this GRI study[13] also contains a review of fatalities and injuries resulting from prior incidents. The review examined when the injuries and fatalities occurred during the incident and whether quick closing valves could have prevented them. The conclusions and observations in this study are summarized as follows:

- 80 incidents were examined over a time period from 1970-1992 which included 28 fatalities and 116 injuries. There was only one incident in which application of a quick closing valve could have prevented the injury that occurred. In all other incidents, immediate burns or impact from the gas released caused the injury or fatality, and quick closing valves would not have mitigated the consequences of the incidents to individuals.

- Of 80 incidents examined, 60 percent were due to outside forces, 15 percent corrosion, 5 percent construction or material defects and 20 percent "other" causes. (Historically, approximately 40 percent of all incidents that occur on gas pipelines are due to outside force.)

- About half of the outside forces incidents release gas immediately at the time of damage which will likely result in immediate injuries/fatalities to operators of excavation and other equipment in close proximity of the pipeline.

These results indicate that there are a number of parameters that need to be considered when dealing with valve closure. The parameters that need to be considered are 1) basis for activating closure of a valve, i.e., manual, automatic based on pressure, leakage, or neighbors call, 2) reliability of the valve closure, 3) time to close valve under accident conditions, and 4) leakage once valve is closed.

SUMMARY AND CONCLUSIONS

The review indicated that existing valve spacing requirements in the fourteen codes reviewed can be divided into the following three categories:

1) specific valve spacings, which are a function of class location, usually an adaptation of the ASME B31.8 valve spacing requirements from the 1950s,
2) valves are spaced as necessary for the safe operation of a pipeline, or
3) valves are spaced so that the volume of gas between valves is less than a specific value.

The review has not found that the rationale for the valve spacing in the codes has a scientific basis other than that they were developed by consensus standards committees that consisted of industry representatives and that these values have been accepted by the industry and regulatory bodies.

No specific valve closure requirements such as automatic, remote control, or manual were found in any of the codes.

The rationale for class location definitions is that they are arbitrary with the numbers of houses or population per unit area encompassing a range in the various codes. It may be that these are appropriate for the countries that use them because of their special circumstances, but that basis could not be identified in the literature.

The basis of the corridor width that is used in many of the codes is a reduction of the ASME B31.8 corridor width requirements by the US DOT/Office of Pipeline Safety (OPS). No report could be located that identified the basis for the corridor width. The OPS corridor width was defined at $\pm$ 220 yds. ($\pm$ 200 m). (Originally, B31.8 used $\pm$ 440 yds [$\pm$ 400 m] corridor width.) This seems in retrospect to be a reasonable distance since the largest burn area found in a review of NTSB reports is 610 ft (186 m). The most technically correct approach to corridor width was found in the UK IGE TD/1 Code, which bases the width on the radiation flux from a file in various diameter and pressure lines. No code presently contains an exclusion zone in which no houses or buildings exist, and it would appear to be unnecessary based on the excellent safety record of the gas transmission industry.

RECOMMENDATIONS

The results indicate that many of the pipeline codes are prescriptive and are based on concepts initiated in the ASME B31.8 code which is more than 40 years old. It appears that an improved set of valve spacing requirements could be developed which are not prescriptive but are performance oriented to provide increased flexibility for operators without affecting the safety of transmission pipelines.

Secondly, with the desire of pipeline companies to operate pipelines at increasingly higher percentages of the yield stress or ultimate stress, it appears that performance guidelines could be developed for a pipeline to operate at these higher stress levels, i.e., 80 percent SMYS, without compromising the safety of a pipeline.

RESEARCH SUMMARY

Title	Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implications for Today's Natural Gas Pipeline System
Contractor	Radian International GRI Contract No. 6032
Principal Investigator	Theresa M. Shires and Matthew R. Harrison
Report Period	June 1998 through December 1998
Objective	To document the early development of the ASME B31.8 Code and federal Pipeline Safety Regulations so that current and future pipeline engineers can understand the basis of these industry standards and regulatory requirements.
Technical Perspective	The B31.8 pipeline industry Code and the Title 49 CFR Part 192 regulatory requirements have evolved over time based on technological developments and engineering advances, as well as political and operational philosophies. Current pipeline Code and Regulations differ significantly from the original documents. An understanding of the Code and regulatory foundations is necessary to interpret and apply these requirements to today's natural gas pipeline systems in the interest of safer and more efficient pipelines.
Technical Approach	Two meetings were held with a number of distinguished pipeline experts to discuss the development of the original B31.8 gas pipeline Code. In addition, the first directors of the Office of Pipeline Safety joined in this effort to provide background on the federal Pipeline Safety Regulations. The focus of this effort was natural gas transmission pipeline design, construction, and operations. Discussions covered the founding principles of the B31.8 Code and the federal Regulations and addressed the following five major topics of interest to the pipeline industry: 1) establishing the bases for operating pressure; 2) class location areas; 3) valve spacing; 4) inspection frequencies; and 5) public communications.
Results	This report presents a compilation of information and discussions with founders of the B31.8 Code and federal Pipeline Safety Regulations. The two group meetings were video taped for archival purposes.
Project Implications	The results of this study provide the natural gas industry with a greater understanding of the founding principles and intentions of the B31.8 Code and federal Pipeline Safety Regulations. Industry can use this information to support continued public benefit, improved safety, and industry growth. GRI Project Manager Dr. Keith Leewis Transmission Business Unit

9.0 Conclusions

Based on the meetings held for this project, it is interesting to note that the concerns of the industry when the 1955 Code Committee was initially developing standards for gas pipelines remain the major concerns of operators today – maintaining the safety of the pipeline system while economically transporting natural gas.

The original B31.1.8 Committee designed the Code with three primary objectives:

1. To represent the established, good engineering practices used to develop, operate, and maintain the existing infrastructure, such that the industry would not be burdened with having to replace vast amounts of good pipe;
2. To make the standards acceptable to the federal government and the public, such that federal regulations (i.e., the Heselton Bill) would not be needed; and
3. To use in material and construction bid documents.

The Code was based on the technological developments of the time, and it was during this time that the industry was rapidly developing new technologies. The Committee wanted the Code to be applicable to current best practices, but flexible enough to provide for new innovations and experience gained by the industry. In fact, during this time, the PRC was formed to develop research efforts in support of the Code. As the research results became available, they were included in the technical discussions supporting the Code development and modifications.

The language used in the 1955 and 1958 versions of the Code was specifically chosen to be performance based. The Committee set out to document safe, acceptable practices and not to prescribe actions. Performance based language carried over into the original Pipeline Safety Regulations. In fact, many of the broad, philosophical considerations of the Code served as the foundation of the Regulations as well.

In the current regulatory environment, it is important to observe that the original intent of the Code was performance and was not to be as prescriptive as the requirements imposed by regulations. To facilitate enforcement, regulations have moved away from being performance based to being more prescriptive. Over time, the Code has been modified to more closely reflect the regulations. For all practical purposes, the U.S. pipeline operators are not compelled to use the Code because the U.S. pipeline industry is regulated by 49 CFR Part 192.

A worldwide initiative is currently underway to develop an international code for pipelines: *ISO/DIS 13623 Pipeline Transportation System for the Petroleum and Natural Gas Industries*. This document is written to satisfy all world conditions related to pipelines. The current B31.8 Committee is also trying to make the Code more applicable to international operations since many of the U.S. gas pipeline companies have or are developing international interests.

Technological developments and engineering advances continue to improve pipeline operations and safety. The pipeline industry works to incorporate these changes into their codes and standards, and the continued development and use of the Code complements the development of the regulatory requirements. Through an understanding of the Code's foundations, the current gas pipeline industry has an opportunity to work with OPS to restore the original performance intentions of the Code and to provide for continued public benefit and improved safety.

REMOTELY CONTROLLED VALVES ON INTERSTATE NATURAL GAS PIPELINES

(Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996)

September 1999

U.S. Department of Transportation
Research and Special Programs Administration
400 Seventh Street, S. W.
Washington, D. C. 20590

utilities. Unfortunately, there is no data known to us to quantify these benefits.

Reduction of risk

Installation of RCVs would reduce risk, but the degree of reduction is unknown. The reduction is primarily due to less gas escaping to the atmosphere after a rupture because RCV closure can be in 10 minutes versus 40 minutes (4) if the valves require manual closing, resulting in possible reduced effects, such as property damage. There is some evidence from the NTSB report on the Edison failure (1), that faster valve closure might have allowed firemen to enter the area sooner to extinguish the blazes and might have controlled the spread of the fires to adjacent buildings. However, a quantifiable value can not be placed on this savings to property damage.

6.2 Proposal

We have found that RCVs are effective and technically feasible, and can reduce risk, but are not economically feasible. We have also found that there may be a public perception that RCVs will improve safety and reduce the risk from a ruptured gas pipeline.

We believe there is a role for RCVs in reducing the risk from certain ruptured pipelines and thereby minimizing the consequences of certain gas pipeline ruptures. We are aware of excessive delays operators have experienced manually closing valves following a pipeline rupture. RCVs ensure that a section of pipe can be isolated within a specified time period after the rupture. Once the ruptured section is isolated and no longer receiving additional gas from upstream in the line, any fire would subside as residual gas in the isolated section is burned.

At many locations, there is significant risk as long as gas is being supplied to a rupture site, and operators lack the ability to quickly close existing manual valves. Any fire would be of greater intensity and would have greater potential for damaging surrounding infrastructure if it is constantly replenished with gas. The degree of disruption in heavily populated and commercial areas would be in direct proportion to the duration of the fire. Although we lack data enabling us to quantify these potential consequences, we believe them to be significant nonetheless, and we believe RCVs may provide the best means for addressing them.

Also, by providing a definitive time when the line would be isolated following a rupture, it is possible to determine how and when any fire would die out. This knowledge provides a basis for risk assessment and response planning, important considerations in certain heavily populated or commercial areas, and an important factor in maintaining public confidence.

There are some locations where RCVs may need to be installed to reduce the risk from escaping gas at a failure when a reasonable time to close a manually operated valve can not be established, even though installation of the RCV would not be cost effective. Although we believe a standard requiring time-to-isolate a ruptured pipeline section may be appropriate, we lack sufficient data to consider one. We are therefore hosting a public meeting on Thursday, November 4, at 1:00 p.m., Room 8236, 400 7th Street SW, Washington, DC. We will seek input on information for specifying the time-to-isolate a ruptured pipeline section. Some of the parameters to consider would be -

- Population density
- Vulnerability of the infrastructure
- Environmental consequences
- Accessibility of existing valves based on changing conditions such as weather and traffic
- Valve spacing

- Operational parameters (such as pipe diameter and operating pressure)

7.0 REFERENCES

(1) National Transportation Safety Board, "Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994," PB95-916501, NTSB/PAR-95/01, January 18, 1995.

(2) C. R. Sparks, et al., (Southwest Research Institute), "Remote and Automatic Main Line Valve Technology Assessment," Final Report to Gas Research Institute, Report No. GRI-95/0101, July 1995.

(3) David W. Detty, P.E., (Battelle Memorial Institute), " Texas Eastern Transmission Corporation, Remote Control Valves Field Evaluation Report, October, 1998."

(4) C. R. Sparks, et al., (Southwest Research Institute), "Cost Benefit Study of Remote controlled Main Line Valves," Final Report to Gas Research Institute, Report No. GRI-98/0076, May 1998.

50272-101

REPORT DOCUMENTATION PAGE	1. REPORT NO. GRI-95/0101	2.	3. PB96-110986

Title and Subtitle Remote and Automatic Main Line Valve Technology Assessment	5. Report Date July 1995 6.
7. Author(s) C. R. Sparks, E. B. Bowles, Jr., C. R. Gerlach, J. P. Harrell, R. J. McKee, and T. B. Morrow	8. Performing Organization Rept. No. SwRI 04-6609
9. Performing Organization Name and Address Southwest Research Institute P.O. Drawer 28510 San Antonio, Texas 78228-0510	10. Project/Task/Work Unit No. 11. Contract(c) or Grant(g) No. (C) 5094-270-2954 (G)
12. Sponsoring Organization Name and Address Gas Research Institute 8600 West Bryn Mawr Avenue Chicago, Illinois 60631-3562	13. Type of Report & Period Covered Final Report Sept. 1994–April 1995 14.

15. Supplementary Notes

16. Abstract (Limit 200 words)

Present equipment in use by the natural gas industry for detection and control of pipeline breaks has proven unreliable for many applications. While the valves and their gas/hydraulic operators normally perform adequately, the detection systems and logic control used to trigger the closure of automatic valves are plagued by reliability problems. Most detectors seek to identify a rupture event by monitoring transient pressure signals that are generated in the pipeline by the quick release of gas. However, the allowable detection sensitivity of these devices is limited by other operational transients in the pipeline with characteristics similar to line breaks. In order to avoid false closures due to normal transients, detector system sensitivity must be severely reduced, in some cases, even to the point of inoperability on a full line break.

Computer modeling can be used to predict the intensity of line break signals and other operational transients within the pipeline. This approach may enhance the reliability of line break detection by evaluating alternative sense parameters, and by identifying a threshold setting or trip level at each valve that best discriminates a line break from other pipeline transient conditions.

17. Document Analysis a. Descriptors

Pipeline Breaks	Automatic Line Valves
Pipeline Rupture	Remote Line Valves
Pipeline Safety	Pipeline Simulation

b. Identifiers/Open-Ended Terms

c. COSATI Field/Group

18. Availability Statement:	19. Security Class (This Report) Unclassified	21. No. of Pages 156
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(See ANSI-Z39.18) See Instructions on Reverse OPTIONAL FORM 272 (4-77) (Formerly NTIS-35)

IX. CONCLUSIONS

A. State-of-the-Art Survey

Conclusions from the state-of-the-art survey are as follows:

(1) The traditional approach to line break detection and control in the U.S. gas pipeline industry has used pneumatic rate-of-pressure-drop detectors and gas or gas/hydraulic operators on main line valves. Seven of the 23 companies surveyed have extensively used these devices, but two companies have recently abandoned them because of (1) unreliability in valving off main line breaks, and (2) an intolerable number of false valve closures triggered by normal pipeline transients.

(2) Although susceptible to operational and false closure problems, automatic control valves using pneumatic ROPD detectors are sometimes effective in isolating a line break. In the absence of a better alternative, they are still used by some companies, but are favored in areas remote from the primary market areas; i.e., where false closures are not as critical. On the other hand, many of the primary market areas are where control is most needed.

When ACV's work properly, they are deemed advantageous in that quicker valve closure is usually achieved than with remote-control valves.

(3) While pneumatic ROPD devices are subject to maintenance-related failures, a more basic problem lies in their inability to discriminate between line break transients and other pipeline transients that occur during normal operation (e.g., compressor station shutdown, load or supply variations, and other valving changes). Attempts to minimize susceptibility to false closures usually consist of decreasing the detection system sensitivity (i.e., requiring larger ROPD's), often to the point of detector inoperability.

(4) Other mechanical/pneumatic problems associated with traditional pneumatic ROPD detector devices include:

(a) Plugging or constricting of the reference orifice with ice, dirt, rust, or hydrates.

(b) Collection of liquids in the reference pressure tank.

(c) Difficulty in adjusting the ROPD trigger level for specific applications.

(d) Defining the proper reference tank volume and orifice size for use in each specific pipeline application.

(5) Reported problems associated with gas and gas/hydraulic-powered operator systems include:

(a) Misadjustment, such as leaving the power gas supply valve closed.

(b) Incomplete valve closures due to decaying supply pressure and increasing valve torque requirements as differential pressure across the valve increases.

- In power gas tank systems, the supply tank may be undersized.

- When power gas is supplied directly from the pipeline, pressure may fall too quickly if the break is nearby and if a delay is built into the rupture detection system.

- Leaks may occur in either the power gas or the hydraulic power system.

(6) In recent years, electronic ROPD sensors have been developed to replace the older pneumatic sensor systems, and can be used with either power gas or gas/hydraulic actuator systems. Several units are now in use on a trial basis by several pipeline companies and, in theory, offer advantages in terms of both reliability and controllability; i.e., in the accuracy and convenience of adjusting the desired rate of pressure drop, and in adjusting the time period over which ROPD data is averaged. In addition, they provide a monitoring mode for defining the magnitude of other pipeline transient signals, and this data can be used to help minimize false valve closures.

Field experience with these devices is as yet insufficient to fully define their performance. It seems clear, however, that when operating in an ROPD mode, they will be susceptible to false closure by other pipeline operational transients when these transients are comparable in magnitude (over the selected averaging time) to that from a line break.

(7) Improved reliability of well-engineered rupture detection and control systems will serve two primary functions:

(a) Improve the reliability of detecting line breaks.

(b) Reduce the incidence of false valve closures.

Because false closures can result in curtailment of customer service, they can thereby precipitate significant safety problems and economic losses among residential, commercial, and industrial customers.

(8) To avoid the adverse effects of false valve closures, many pipeline operators prefer to leave the valve closure decision to human judgment rather than to an automatic valve.

  (a) A few companies require that the final decision be made by a person at the rupture site.

  (b) Others rely on the decision of personnel at Gas Control, based upon their review of SCADA data from nearby locations, and their knowledge of the pipeline. Once the decision is made, the valve may be closed remotely (if remote valves are present) or by personnel dispatched to the site.

(9) Potential improvements in the reliability of both ACV's and RCV's must come primarily from improved detector system design techniques that match sensor system type, location and sensitivity to pipeline operating conditions, pipeline configuration (looped vs. single lines, valve location, etc.), and the potential signal strength of a line break. There are several potential approaches available for improving the detectability of line break transients in a pipeline environment. These include:

  (a) Improved signature analysis (pattern recognition) techniques that characterize rupture signals better than does ROPD.

  (b) Several additional parameters at the valve site might be detected as confirming signals or as a part of the pattern recognition process; e.g., acoustic pulses, line flow velocity and direction, crossover flow, line-to-line differential pressure, etc. These might be adaptable to either automatic or remote valve systems.

  (c) Data from other points in the nearby pipeline system (e.g., multiple sense points between valves) might also be used to improve or confirm the detection of a line break.

(10) Most pipeline companies have SCADA systems that provide real-time pressure and flow rate data from compressor stations and other critical points in the pipeline. In the absence of proven line break detectors, SCADA data and other means (phone calls, etc.) are relied upon by the pipeline operator for detecting line breaks.

(11) Remote-control valves are widely used at compressor stations and at other critical points in the pipeline. In some cases, these are used for shutting in

a line segment when a break is suspected. In other cases, company policy dictates that the valve closure can be made only by on-site field personnel. The reluctance to remotely close valves comes from the adverse operational and safety effects that can result from a false valve closure. The risks associated with a false closure are deemed by some to be more significant than those of an unconfirmed line break signal.

(12) Most compressors have low pressure trips that will shut down to protect the compressor unit when suction pressure drops below a prescribed level. Some have such detectors on the station discharge as well, specifically for line break control.

(13) A variety of less frequently used line break detector systems have been devised and are currently in use for both automatic and remote valves. These include the measurement of parameters such as excess line flow, excess valve pressure drop, and unbalanced flow and/or pressures in looped lines. Many of the detection signals are transmitted via SCADA for action by Gas Control, while in other cases, autonomous local control is maintained.

(14) In those systems where SCADA data is used to monitor for line breaks, alarms and visual monitoring provide the most common detection approaches. In some cases, however, trending or computer simulations (using pipeline flow models) are used to evaluate SCADA data. Any significant deviation between SCADA data and computer predictions generates a line break alarm.

(15) Early valve closure decreases the amount of gas loss due to a pipeline break. Even with immediate valve closure, the amount of gas in the isolated pipeline section will vent for some time. The actual time is dependent on the pipeline diameter and configuration, operating conditions, and break size and location. Therefore, the primary result of early valve closure in a typical system is to reduce the venting duration of a full line break from perhaps an hour or two (if valves are closed manually) to perhaps 30 to 60 minutes in the case of immediate valve closure (for a 20-inch, 1000 psi line, 10 - 15 miles in length).

When gas ignition occurs, it normally occurs very shortly after the line breaks -- typically two to ten minutes. Therefore, early valve closure will not usually prevent ignition, but can reduce the duration of flare burndown and radiant heating in the surrounding area. This may, thereby, reduce the incidence of radiant ignition of surrounding structures. Typically, however, the most severe conflagration occurs with plume ignition. The severity of this conflagration is determined by plume size: a function of pipeline operating conditions, break size, atmospheric conditions, and time to ignition. After this initial concentration is exhausted (the plume burns), the subsequent flare from the venting gas is less intense and less likely to contribute to further damages.

B. Conclusions from Computer Simulation Studies

(1) Transient flow computer models can be used to accurately predict the blowdown time for a line break in either single or looped line systems, and to predict the transient pressures and flows that propagate through the pipeline as a result of the break (rupture).

(2) These models can also predict the background transient noise produced by nearby compressor stations, branch loads, and other main line or branch line valves, and can thereby predict the masking effects of this noise on line break detection equipment located at points along the line.

(3) These models provide a predictable design and evaluation capability for defining the adequacy of proposed ACV protective systems, and a potential technique for specifying the required detector sensitivity based on the following parameters.

  (a) Initial operating conditions (line pressure profile and flow rate).

  (b) Pipe size.

  (c) Single or looped lines, with or without branch lines.

  (d) Crossovers open or closed.

  (e) Valve size, spacing, and percent opening.

  (f) Break size and location relative to block valves.

  (g) The potential masking effects of start-up or shutdown of upstream and downstream compressor stations.

  (h) The potential masking effects of branch loads or valving changes.

  (i) ACV detection parameters used (e.g., rate of pressure, drop, rate of flow change, etc.).

  (j) Gas composition and temperature.

(4) Computer modeling confirms field experience that no single detection parameter (such as ROPD or local flow velocity) is suitable for all ACV applications. If sensors are positioned only at the valve locations, then line break signals in some instances can be masked by other pipeline

operational transients, unless the valves are located very close together. For ACV locations near compressor stations, the line break ROPD signals received from a rupture at the far end of the line section being protected will often be lower in amplitude than compressor noise. If sensitivity of the ROPD detectors is reduced to prevent false valve closures, they may miss the line break signals as well.

(5) In multiple parallel lines (looped lines) ACV's have three disadvantages when crossovers are open:

(a) Flow from the other line(s) feeds the ruptured line and pressure does not fall as fast (ROPD signal is lower) than in single line systems. Reliable sensing is therefore more difficult in the presence of other pipeline transients.

(b) ROPD signals provide no means of identifying which of the lines has sustained a break.

(c) Since pressure in the looped lines tend to equalize, ROPD signals in the unruptured line(s) will be comparable to that in the ruptured line. Unnecessary closure of valves in the parallel lines can result, curtailing all pipeline transportation.

(6) In many such cases (especially in looped lines with open crossovers), alternative detection signals, such as crossover flow rate or line-to-line differential pressure, can be used to enhance break detection for either ACV's or RCV's. These systems have an added advantage in that they can identify which line has sustained the break.

(7) The sensitivity and reliability of ROPD systems can be enhanced by locating additional ROPD sensors between valves. Detector location is much more important than valve spacing in improving the reliability of ACV's and RCV's, and in preventing false closures. If, for example, valve spacing is 20 miles and detectors are located at 5-mile intervals, then detector sensitivity can be substantially reduced (to avoid false closures) and still detect a line break in that local area. Detectors must communicate, however, with both upstream and downstream ACV's or with a central location for RCV actuation. Such an approach may be particularly advantageous in Class 3 and 4 locations because electrical power and communications are often available.

(8) While simulation studies have demonstrated the importance of defining fluid transient signals generated by a line break and by other operational transients, effective use of the design principles developed in this process requires a quantitative prediction technique to define the relative intensity of these signals as seen at sensor points (normally, valve location) along

the pipeline. Two approaches are available for incorporating these predictive processes into the design and selection of line break control equipment; viz:

(a) Study each proposed (or existing) system on an individual basis to evaluate potential detection systems, comparing rupture signal strength to those of other background transients.

(b) Analyze and catalogue a series of standard designs covering a range of typical pipeline configurations and operating conditions.

(9) As a part of these design analyses, investigations should also be made of various alternative sense parameters that could be used in combination to augment or replace more conventional ROPD sensor systems where reliability needs dictate. The resulting parameters could be used for either ACV's or RCV's, or simply as an alarm at the pipeline dispatching center for those applications that have telemetered communications.

Multiple sense points can also provide a means for avoiding the "domino" effect, wherein closure of one valve produces transients that close other valves up and down the pipe. In looped lines, this effect can shut down the entire pipeline system between compressor stations.

(10) When a full line break occurs in a single line system, each segment of the line (upstream and downstream) blows down independently, and substantially different venting times for the two sections can be evidenced depending upon just where the line break occurs. If a break occurs at the midpoint of a line segment, blowdown time for each of the two segments is about one-third of the time required for a break at one end. In general, large diameter lines blow down more quickly than small diameter lines.

(11) Computer simulations provide a convenient means of predicting blowdown time and lost product for either a full or partial break in single and looped-line gas transmission systems. By simulating flows and pressures in the entire pipeline length between compressor stations, transient flow models can account for delayed valve closures, feed flow from contiguous line segments upstream and downstream of the ruptured section, and crossover flow from parallel lines. Because isolation valves typically do not close immediately when a break occurs, a portion of the lost gas often comes from outside the ruptured segment itself, and lost product can be substantially more than the original line pack in the ruptured section.

Specific simulation data supporting and illustrating these conclusions are given in Section V of this report.

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METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY VOLUME 2: TECHNICAL REPORT

FINAL REPORT

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open-ended lines, starter open-ended lines, compressor seals, pressure relief valves, and other components such as cylinder valve covers and fuel valves.

Fugitive emissions from compressor stations are dominated by emissions from components related to compressors, which emit 57.5 Bscf, while emissions from all of the remaining components not associated with compressors contribute only 9.9 Bscf.

Fugitive emissions were estimated from measurement data collected at 15 compressor stations using the GRI Hi-Flow™ approach.[24] Leaking components were identified using soaping tests and all leaking components were directly measured using the GRI Hi-Flow™ sampler or a direct flow measurement, such as a rotameter. Based on the measurement data, fugitive emissions from the compressor blowdown open-ended line were found to be the largest source. Compressor blowdown open-ended lines allow a compressor to be depressurized when idle, and typically leak when the compressor is operating or idle. There are two primary modes of operation leading to different emission rates for compressor blowdown open-ended lines:

- Blowdown valve is closed and the compressor is pressurized, either during normal operation or when idle.
- Compressor blowdown valve is open. This occurs when the compressor is idle, isolated from the compressor suction and discharge manifolds, and the blowdown valve is opened to depressurize the compressor.

The fugitive emission rate is higher for the second operating mode when the blowdown valve is open, since leakage occurs from the valve seats of the much larger suction and discharge valves. Separate component emission factors were developed for the two operating modes of the compressor blowdown open-ended line. An overall average component emission factor was derived for compressor blowdown open-ended lines by determining the fraction of time transmission compressors operate in each mode (i.e., pressurized and depressurized).

The majority of compressor fugitive emissions result from the transmission and storage segments, where a high number of very large compressors exist. Since compressors are also a part of production facilities and gas plants, the compressor component emission factors developed for the transmission and storage segments were also used for compressor components in those segments.

Production Facilities

Annual fugitive emissions from gas production facilities in the United States were estimated to be 17.4 Bscf. Component emission factors for fugitive equipment leaks in gas production were estimated separately for onshore and offshore production due to differences in operational characteristics. Regional differences were found to exist between onshore production in the Atlantic and Great Lakes region (i.e., Eastern U.S.) and the rest of the country (i.e., Western U.S.), and between offshore production in the Gulf of Mexico and the Pacific Outer Continental Shelf (OCS). In general, these regional differences were due to differences in the number, type, age, and leak detection and repair characteristics of equipment. Therefore, separate measurement programs were conducted to account for these regional differences.

For onshore production in the Eastern U.S., component emission factors and average component counts were based on a measurement program using the GRI Hi-Flow™ sampler to quantitate emission rates from leaking components.[22] A total of 192 individual well sites were screened at 12 eastern gas production facilities.

Fugitive emissions from onshore production in the rest of the U.S. (excluding the Eastern U.S.) were estimated using the EPA protocol approach. Component emission factors were based on screening and enclosure data collected from 83 gas wells at 4 gas production sites in the Western U.S.[21] The average component counts were based on data from the onshore production measurement program and additional data collected during 13 site visits to gas production fields.[10]

Emissions from equipment leaks from offshore production sites in the U.S. were quantified based on two separate screening and enclosure studies using the EPA protocol approach:

- The oil and natural gas production operations measurement program,[21] which included 4 offshore production sites in the Gulf of Mexico; and
- The offshore production measurement program,[37] which included 7 offshore production sites in the Pacific OCS.

Gas Processing Plants

Fugitive emissions from gas processing plants contribute 24.4 Bscf to national annual methane emissions. The majority of fugitive emissions from gas processing plants are attributed to compressor-related components, which account for 22.4 Bscf. The component emission factors for compressor-related components in gas processing plants were based on the fugitives measurement program at 15 compressor stations.[10] Fugitive emissions from the remaining gas plant components, not associated with compressors, were estimated based on the oil and gas production measurement program.[21] In the oil and gas production measurement program, equipment leaks from a total of 8 gas processing plants were measured using EPA protocol approach.

Meter and Pressure Regulating Stations

Fugitive emissions from meter and pressure regulating stations (M&PR stations) contribute 31.8 Bscf to total annual methane emissions. Emissions from this category of surface equipment were measured using the tracer measurement approach, and therefore were reported separately from other categories of surface equipment fugitives. A total of 95 M&PR facilities were measured using the tracer technique.[12]

The primary losses from M&PR stations include both fugitive emissions and, in some cases, emissions from pneumatic devices. Since the tracer measurement technique used does not differentiate between fugitive and vented emissions, the vented pneumatic emissions are therefore included in the fugitive category by default. Some pressure regulating stations use gas-operated pneumatic devices to position the pressure regulators. These gas-operated pneumatic devices bleed to the atmosphere continuously and/or when the regulator is activated for some system designs. Other designs bleed the gas downstream into the lower pressure pipeline and, therefore, have no losses associated with the pneumatic devices.

Tracer measurements were used to derive the emission factors for estimating emissions from M&PR stations in both the transmission and distribution segments of the gas industry. The total emissions are a product of the emission factor and activity factor, which were stratified into inlet pressure and location (above ground versus in a vault) categories to improve the precision of the emissions estimate.

Metering/pressure regulating stations in the distribution segment include both transmission-to-distribution custody transfer points and the downstream pressure reduction stations. The emission factors for distribution are based on the average measured emissions for each station category, and the activity factors are based on the average data supplied by 12 distribution companies. The annual methane emissions for the M&PR stations in the distribution segment of the gas industry are 27.3 Bscf.

For the transmission segment, the stations include transmission to transmission custody transfer points and transmission-to-customer transfer. Emission factors for the transmission segment are derived from the tracer measurement database for M&PR stations, and the activity factors are based on survey data from six transmission companies. The annual estimated methane emissions for the transmission segment are 4.5 Bscf.

Customer Meter Sets

Fugitive emissions from commercial/industrial and residential customer meter sets contribute 5.8 Bscf to total national emissions. The average leak rate per residential meter set is only 0.01 scf/hr, but there are approximately 40 million customer meters located outdoors. The meter sets include the meter itself and the related pipe and fittings. Methane emissions from commercial and residential customer meter sets are caused by fugitive losses from the connections and other fittings surrounding the meter set. No losses have been found from the meter itself; only the pipe fittings surrounding the meter have been found to be leaking.

Methane emissions from customer meter sets were estimated based on fugitives screening data collected from 10 cities across the United States.[10,24,26] Although a total of around 1600 meter sets were screened as part of the GRI/EPA study, only about 20% of the meter sets screened were found to be leaking at low levels. For the majority of customer meter sets screened, the GRI Hi-Flow device was used to develop emission factors. For the other meter sets screened, the EPA protocol approach was used to convert the screening data into emission rates.

Emission factors for residential customer meter sets were defined as the average methane leakage rate per meter set for outdoor meters. Emissions from indoor meters are much lower than for outdoor meters because gas leaks within the confined space of a residence are readily identified and repaired. This is consistent with the findings that pressure regulating stations located in vaults have substantially lower emissions than stations located above ground. Emission factors for commercial/industrial meter sets were estimated separately as the average emission rate per meter set.

The activity factors for residential customer meter sets were defined as the number of outdoor customer meters in the United States. The activity factor was based on published statistics including a breakdown of residential customer meters by region in order to estimate the number of meter sets located indoors. Data were obtained from 22 individual gas companies within different regions of the United States to estimate the number of indoor residential customer meters.

4.2.2 Underground Pipeline Leaks

Fugitive leakage from underground piping systems contributes 48.4 Bscf to total methane emissions. Pipeline leaks are caused by corrosion, material defects, and joint and fitting defects/failures. Based on limited leak measurement data from two distribution companies, leakage from underground distribution mains and services was targeted as a potentially large source of methane emissions from the gas industry.

A leak measurement technique was developed (Section 3.2.1) and was implemented as a method to quantify methane emissions from underground pipelines in the natural gas industry.[11] A total of 146 leak measurements were collected from the participating companies. These data were used to derive the emission factors for estimating methane leakage from distribution, transmission, and production underground pipelines.

The total emissions are a product of the emission factor and activity factor, and are stratified by pipe use (mains versus services) and pipe material categories to improve the precision of the estimate. The total annual methane emissions from underground pipeline leaks in all segments are 48.4 Bscf.

The soil oxidation rates of methane were experimentally determined to be a function of the methane emissions rate, pipe depth, and soil temperature. The methane leakage rate for underground pipelines was determined to be a function of the pipe service (main versus services) and the pipe material type. In general, the larger the leakage rate per leak, the lower the soil oxidation rate. Because of the type of pipelines in service in the distribution segment, the overall leakage rate per peak is lower. Therefore, the overall oxidation rates for distribution pipelines is higher than for transmission or gathering lines.

In the distribution segment, activity factors were based on the national database of leak repairs broken down by pipe material using information from ten companies, and then combined with historical leak records provided by six companies. The activity factors represent the number of equivalent leaks that are continuously leaking year round. (Repaired leaks are counted as fractional leaks.)

The activity factor combined with the emission factors derived from the leak measurement data produced an overall methane emissions estimate of 41.6 Bscf, which includes an adjustment for soil oxidation. The largest contributor to the overall annual emissions was cast iron mains, followed by unprotected steel services and mains. The average soil oxidation rate applicable to distribution piping was 18%, which primarily affects the emissions from cast iron mains, which have low leak rates per leak.

In the transmission and production segments, the estimated methane leakage was based on the emission factors derived from the leak rates measured on distribution mains and on activity factors derived from a nationally tracked database of pipe mileage/leak repairs. For transmission pipeline leakage, the estimated annual methane emissions were 0.2 Bscf, which includes an adjustment for soil oxidation.

ATTACHMENT 2

PRELIMINARY REPORT ON THE REPLACEMENT OR RETROFIT OF MANUALLY OPERATED VALVES WITH AUTOMATICALLY OR REMOTELY CONTROLLED VALVES ON PG&E GAS TRANSMISSION PIPELINES

The letters from Paul Clanon to PG&E, dated September 13, 2010 (Item 11) and September 17, 2010 (Item 7), and Ordering Paragraph 21 of Resolution L-403 directed PG&E to conduct a review of gas transmission line valve locations in order to determine a list of locations at which manual valves could be replaced by remotely-operated or automatic shut-off valves, an estimate of the costs of such replacement valves, and a description of the types of valves commercially available.

PG&E responded on September 20, 2010, affirming its commitment to conduct the review and provide the list and estimates requested.

SUMMARY

What follows is PG&E's preliminary report regarding the replacement or retrofit of manually operated valves with remotely controlled or automatic shut-off valves on its gas transmission system. PG&E proposes that this preliminary analysis be included in its Pipeline 2020 program and be reviewed by the CPUC and a third-party natural gas transmission expert in order to validate the analysis. Based on our preliminary analysis, PG&E estimates there are approximately 300 manual valves on over 565 miles of pipeline that should be further evaluated for potential replacement or retrofit.

There currently are no specific regulations governing the use of automated valves. As part of PG&E's Pipeline 2020 program, PG&E has engaged a third-party firm to review these preliminary conclusions and to provide recommendations in connection with the more detailed plan that PG&E will file with the Commission for its consideration. The firm will examine the specific requirements of PG&E's system, benchmark PG&E's practices against those of other pipeline operators, and assess the potential to replace or retrofit manually operated valves with remotely operated or automatic shut-off valves, as well as assess adding new valves. It will also identify associated enhancements to gas system operations, including protocols, training and system upgrades to enable effective use of the valve technology.

This study has begun and is expected to be completed by the end of the second quarter of 2011. PG&E will share the results of that comprehensive study with the CPUC.

BACKGROUND: Types and Uses of Automated Valves

There are two types of automated valves:

- Automated Remotely Controlled Valves (RCVs) allow a mainline valve to be opened and closed by a remote operator located at a gas control center.

- Automatic Line Rupture Shut-off Valves (ASVs) automatically close when they detect a line rupture (*e.g.* falling pressure, increasing flow rate) or any other condition that they are programmed to detect. These valves close without human intervention.

If a gas line is ruptured or there is another type of unplanned gas release, automated valves of either type can close the affected line much more quickly than a manually operated valve, isolating the ruptured section and reducing the volume of gas vented at the pipeline break. Automated valves do not prevent ruptures. Studies by pipeline experts indicate that most of the harm to persons and property following a natural gas pipeline rupture typically occurs within a few seconds or minutes of the initial rupture and energy release, before even an automated valve of either type can respond.

ASSESSMENT METHODOLOGY

PG&E considered a number of screening criteria to identify preliminary candidates for valve replacements, including:

- *Pipeline location.* PG&E's preliminary analysis focused on pipeline segments located within high consequence areas (HCAs) and took account of other environmental factors such as proximity to an earthquake fault, landslide areas, or major waterways.
- *Pipeline characteristics.* PG&E focused on a number of pipeline characteristics, including materials, age, diameter, operating pressure, and wall thickness.

PRELIMINARY ASSESSMENT RESULTS

Based on these screening criteria, PG&E identified approximately 565 miles of HCA pipeline for further evaluation. Within these 565 miles, PG&E estimates there are approximately 300 candidate valves for automation. PG&E is about one-third of the way through its evaluation of these candidate valves. Maps showing the general location of the valves in this first phase of evaluation are included as Appendix A.[3] A list of those general valve locations is included as Appendix B.[4] PG&E will continue to assess the remaining two-thirds of the candidate valves with the assistance of a third-party firm and provide a more detailed plan with the Commission as part of its Pipeline 2020 program.

RANGE OF POTENTIAL COSTS

The cost of valve replacements or retrofits is location-specific and varies significantly. Where the valve is easily accessible and requires only a retrofit, the cost could be as low as $100,000. In areas that are more difficult to access and require a valve replacement,

[3] A number of the candidate valves are located on the three parallel pipelines in the San Francisco Peninsula. These three pipelines provide gas to over 18% of PG&E's gas accounts. They are connected together (cross-tied) at various points along their route, beginning at Milpitas Terminal and ending in San Francisco. The potential valve replacement candidates shown in Appendix A include valves on both these mainline and crossties.

[4] PG&E will share more detailed valve location information with the Commission and local first responders.

the cost could be as high as $1,500,000.[5] Other factors affecting cost will be considered and addressed in our refined analysis. These factors include:

- The availability of a Supervisory Control and Data Acquisition (SCADA) communication points at the site;
- The availability of telecommunications and electric power facilities at the site;
- The scope of protocols, training and system upgrades and enhancements to ensure effective operation of the automated valve technology; and
- The complexity of isolating and taking portions of the system out-of-service to perform the installation work.

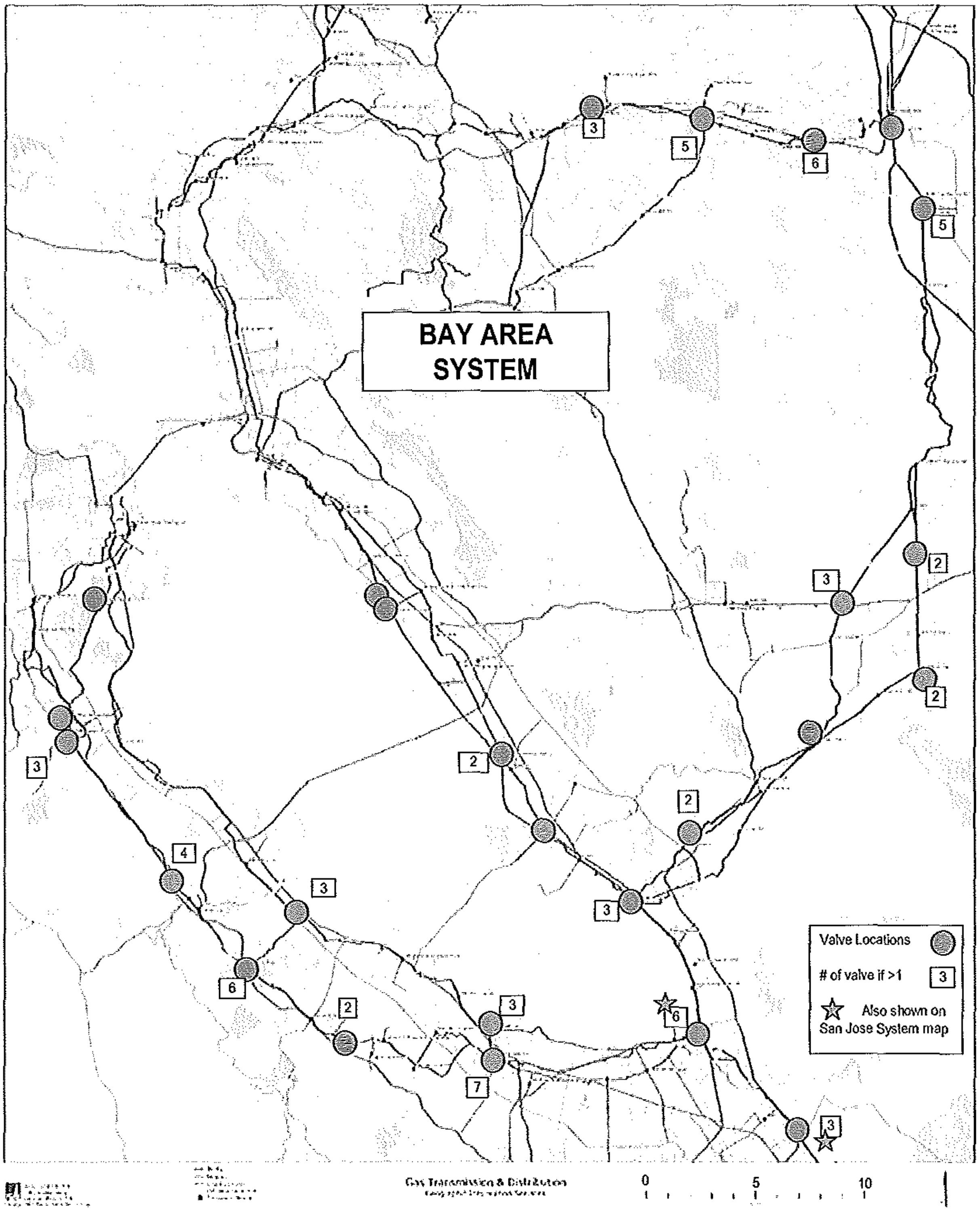
PG&E's estimates primarily reflect capital costs. Operation and maintenance costs, and costs for improving System Gas Control to provide increased oversight for remote control points have not been included in the cost estimates provided in this preliminary report, but will be included in the results of the comprehensive study.

NEXT STEPS

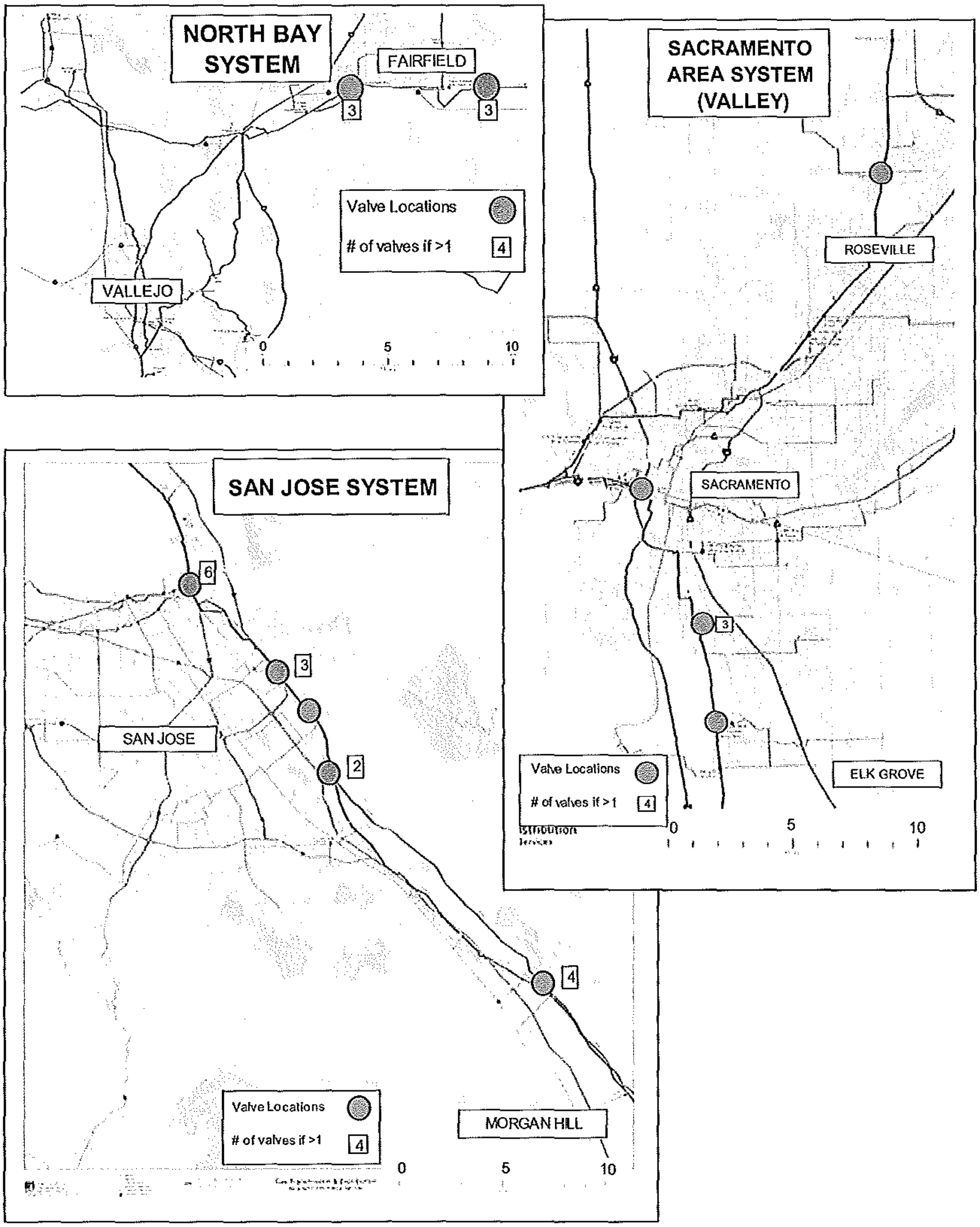
As part of the Pipeline 2020 program, PG&E has engaged a third-party firm to review and refine the preliminary analysis. The detailed study scope is included in Appendix C.

[5] Based on PG&E's past experience, the estimated average cost of installing a valve with automatic or remote controls at an existing manual valve for a large diameter (20" and larger) pipe is approximately $750,000.

APPENDIX A
Location of Potential Valve Replacement Candidates – Initial Evaluation



APPENDIX A, continued
Location of Potential Valve Replacement Candidates – Initial Evaluation



APPENDIX B
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
East Bay	L191	Antioch
East Bay	L191	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
East Bay	SP-5	Antioch
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L114	Brentwood, Unincorporated
Bay Area Loop	L303	Brentwood, Unincorporated
Bay Area Loop	L303	Brentwood, Unincorporated
Peninsula	L109	Hillsborough
Peninsula	L132	Hillsborough
Peninsula	L132	Hillsborough
Peninsula	L132	Hillsborough
East Bay	SP-3	Concord
East Bay	SP-3	Concord
East Bay	SP-3	Concord
Peninsula	L132B	Daly City
Sac Valley	L108	Elk Grove
Bay Area Loop	L107	Fremont
East Bay	L153	Fremont
Bay Area Loop	L303	Fremont
Bay Area Loop	L107	Fremont
Bay Area Loop	L131	Fremont

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Bay Area Loop	L131	Livermore
Bay Area Loop	L131	Livermore
Bay Area Loop	L131	Livermore
Bay Area Loop	L114	Livermore
Bay Area Loop	L303	Livermore
Bay Area Loop	L131	Alameda County
Bay Area Loop	L114	Livermore
Bay Area Loop	L303	Livermore
Peninsula	L109	Menlo Park
Peninsula	L132	Menlo Park
San Jose	L100	Milpitas
Peninsula	L101	Milpitas
Peninsula	L109	Milpitas
Peninsula	L132	Milpitas
Backbone	L300A	Milpitas
Backbone	L300B	Milpitas
Backbone	L300A	Morgan Hill
Backbone	L300A	Morgan Hill
Backbone	L300B	Morgan Hill
Backbone	L300B	Morgan Hill
Peninsula	L101	Mountain View
Peninsula	L101	Mountain View
Peninsula	L101	Mountain View
Peninsula	L109	Mountain View
Peninsula	L109	Mountain View

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Peninsula	L109	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132	Mountain View
Peninsula	L132A	Mountain View
East Bay	L153	Newark
Bay Area Loop	L303	Oakley
East Bay	L191	Pittsburg
East Bay	SP-3	Pittsburg
East Bay	SP-3	Pittsburg
East Bay	SP-3	Pittsburg
East Bay	SP-3	Pittsburg
Peninsula	L109	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L132	Redwood City
Peninsula	L147	Redwood City
North Bay	L210A	Solano County
North Bay	L210A	Solano County
North Bay	L210A	Solano County
Sac Valley	L123	Roseville
Sac Valley	L108	Sacramento
Sac Valley	L108	Sacramento
Sac Valley	L108	Sacramento

APPENDIX B, continued
List of Potential Valve Replacement Candidates – Initial Evaluation

System	Line	City
Sac Valley	L108	Sacramento
Peninsula	L132	San Bruno
Peninsula	L109	San Bruno
Peninsula	L132	San Bruno
Peninsula	L132	San Bruno
Peninsula	L101	San Carlos
Peninsula	L101	San Carlos
Peninsula	L101	San Carlos
San Jose	L100	San Jose
Backbone	L300A	San Jose
Backbone	L300B	San Jose
Backbone	L300B	San Jose
Backbone	L300B	San Jose
San Jose	L100 / 0821-01	San Jose
East Bay	L153	San Leandro
East Bay	L153	San Leandro
North Bay	L210A	Suisun City
North Bay	L210A	Suisun City
North Bay	L210A	Suisun City
East Bay	L153	Union City
East Bay	L153	Union City

APPENDIX C
Scope of Study

PG&E will engage one or more third-party firms to conduct a comprehensive analysis of valve automation across PG&E's natural gas transmission system. This third-party analysis will include the following items, as well as review of (and refinements to) PG&E's preliminary assessment. This third-party analysis will deepen both PG&E's and the industry's understanding of whether and where ASV/RCV equipment should be used. Among other things, the third-party analysis will:

1. Research the industry's use of ASV/RCV equipment on gas transmission systems and identify best practices for design and operation, including the alternatives and merits of available ASV/RCV technology.
2. Survey major gas pipeline operators to collect information on the reasons operators use this equipment, their operating experience, the technology they employ, and the advantages and disadvantages the operators perceive to exist for the use of this technology in general, as well as the specific technology employed by the operator.
3. Evaluate distinctions in how ASV/RCV equipment is employed between FERC regulated pipeline systems, intrastate systems, gas utilities (transmission and distribution) and international pipeline systems.
4. Review PG&E's deployment of ASV/RCV equipment and manual isolation valves and the development of alternative deployment levels, and assess the pros and cons of various levels of additional deployment.

The following specific assessments will be performed:

- Evaluate and improve the pipeline segment selection criteria described above, developed as part of the preliminary assessment.
- Examine the reliability of ASV/RCV technology and the associated required maintenance activities and costs.
- Examine industry and federal government analyses of the merits of ASV/RCV equipment, including a review of state code changes which may have been adopted subsequent to the Texas Eastern Transmission Corporation (TETCO) pipeline explosion in New Jersey in 1994.

PG&E will also work with the third-party firm(s) on the following implementation issues related to ASV/RCV installations:

- Examine the impact of ASV/RCV expansion on PG&E's SCADA system.
  a) System capacity to provide data and control communications.
  b) Challenges related to installing SCADA at a host of remote sites.
  c) Required enhancements to Gas System Operations protocols and training.

APPENDIX C, continued
Scope of Study

- Examine the extent to which remote control will impact operating decisions, the protocols and risk assessment required to make those decisions, and the level of field verification required.
- Examine the feasibility of adding ASV/RCV to valves in a relatively short time period (*e.g.,* permit requirements or land rights for significant station modification or creation of new stations could require significant lead times).
- Examine the construction feasibility to determine obstacles that are particularly costly and time-consuming to resolve (*e.g.* valves could require replacement and/or relocation because they cannot be automated in their current location).
- Examine the extent to which the addition of automation equipment above ground poses a heightened security risk because the equipment is more visible or accessible to persons other than trained and authorized personnel.
- Assess the need for additional physical resources to replace, retrofit or install ASV or RCV valves.

PG&E has reviewed preliminarily the industry literature related to pipeline isolation and the use of ASV/RCV technology. These studies were used to conduct the preliminary assessment and develop this report. A third-party firm will undertake a more thorough review of this documentation and also investigate additional industry literature available on this subject.

1. Eiber, R.J. and McGehee, W.B., *Design Rationale for Valve Spacing, Structure Count, and Corridor Width*, PR249-9631, PRC International, May 30, 1997.
2. Shires, T.M. and Harrison, M.R., *Development of the B31.8 Code and Federal Pipeline Safety Regulations: Implication for Today's Natural Gas Pipeline System*, GRI-98/0367.1, December 1998.
3. Sparks, C.R. et al., *Remote and Automatic Main Line Valve Technology Assessment, Appendix, B*, GRI-95/0101, July 1995.
4. Sparks, C.R., Morrow, T.B. and Harrell, J.P., *Cost Benefit Study of Remote Controlled Main Line Valves*, GRI-98/0076, May 1998.
5. Texas Eastern Transmission Corp., *Natural Gas Pipeline Explosion and Fire*, NTSB/PAR-95/01.
6. Process Performance Improvement Consultants, (P-PIC), White Paper on Equivalent Safety for Alternative Valve Spacing, Draft April 18, 2005.
7. U.S. Department Of Transportation, Research and Special Programs Administration, Remotely Controlled Valves on Interstate Natural Gas Pipelines (Feasibility *Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996)*, September 1999.
8. Gas Research Institute 00/0189 "A Model for Sizing HCA's Associated with Natural Gas Pipelines", December 2001.

APPENDIX C, continued
Scope of Study

9. Eiber, R.J. and Kiefner and Associates, *Review of Safety Considerations for Natural Gas Pipeline Block Valve Spacing (To ASME Standards Technology, LLC)*, July 2010.

REMOTELY CONTROLLED VALVES ON INTERSTATE NATURAL GAS PIPELINES

(Feasibility Determination Mandated by the Accountable Pipeline Safety and Partnership Act of 1996)

September 1999

U.S. Department of Transportation
Research and Special Programs Administration
400 Seventh Street, S. W.
Washington, D. C. 20590

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REPORT

Remotely Controlled Valves on Interstate Natural Gas Pipelines
(Feasibility Determination Mandated by The Accountable Pipeline Safety and Partnership Act of 1996)

1.0 SCOPE AND PURPOSE

This report is in response to a Congressional mandate in the Accountable Pipeline Safety and Partnership Act of 1996 to survey and assess the effectiveness of remotely controlled valves (RCVs) on interstate natural gas pipelines and to determine their technical and economical feasibility to shut off gas after a rupture.

This report contains a discussion of the results of a public meeting held in Houston, Texas on October 30, 1997 for the purpose of gathering information and discussing issues relevant to the survey and assessment. The report also contains the results of an RCV field evaluation conducted by Texas Eastern Transmission Corporation (TETCO) as part of a Consent Order issued by the Office of Pipeline Safety (OPS) (CPF 15102) to provide information on TETCO's experience with RCVs. There is also a discussion of status briefings before the Technical Pipeline Safety Standards Committee (TPSSC) and a cost versus benefit study.

The report addresses the four main issues raised by the Congressional mandate to study RCVs, i.e., effectiveness, technical feasibility, economic feasibility, and risk reduction. The report concludes with a proposal for further action, which is a public meeting to seek input on information for specifying the time-to-isolate a ruptured pipeline section.

2.0 BACKGROUND

2.1 Congressional Mandate

The Accountable Pipeline Safety and Partnership Act of 1996 (codified at 49 U.S.C. 60102 (j)) mandated that:

- "Not later than June 1, 1998, the Secretary [of Transportation] shall survey and assess the effectiveness of remotely controlled valves to shut off the flow of natural gas in the event of a rupture of an interstate natural gas pipeline facility and shall make a determination about whether the use of remotely controlled valves is technically and economically feasible and would reduce risks associated with a rupture of an interstate natural gas pipeline facility."

- "Not later than one year after the survey and assessment are completed, if the Secretary has determined that the use of remotely controlled valves is technically and economically feasible and would reduce risks associated with a rupture of an interstate natural gas pipeline facility, the Secretary shall prescribe standards under which an operator of an interstate natural gas pipeline facility must use a remotely controlled valve. These standards shall include, but not be limited to, requirements for high-density population areas."

This action by Congress was in response to a high pressure gas transmission pipeline failure in Edison, New Jersey on March 23, 1994. The failure of the 36-inch pipeline operated by TETCO resulted in ignition of the escaping gas and creation of a fireball 500 feet high. The incident report filed with the Research and Special Programs Administration (RSPA) reported no fatalities and two people requiring inpatient hospitalization. Radiant heat from the fireball ignited the roofs of buildings located more than 100 yards from the failure, destroyed 128 apartments and resulted in the evacuation of 1,500 people. The casualties were limited because the few minutes between the time of the failure, the fire, and the radiant heat from the fire igniting the apartments, allowed residents to vacate the area. The gas transmission company took 2½ hours to isolate the ruptured section of pipeline by operating manually operated valves, which contributed to the severity of the damages[1]. (1)[2]

2.2 Public Meeting

[1]The main contributor to the length of time to isolate the failed section was that the upstream valve closest to the rupture (about 2000 feet away) relied on pipeline gas pressure to power the valve actuator to close the valve and the pipeline pressure was insufficient for the task due to the rupture. The valve lacked redundant power, such as bottles of compressed gas, to operate the valve actuator to close the valve. This valve could not be closed manually because of differential pressure across the valve made hand wheel turning difficult and the number of revolutions to close (700-750) was excessive. When this valve could not be manually closed, the next closest valve was closed. It took considerably time to reach the next closest valve because of traffic.

[2]Numbers refer to references in Section 7.0 of this report.

By public notice in the Federal Register (62 FR 51624; Oct.2, 1997), we invited representatives from industry, state and local government, and the public to a public meeting on the use of RCVs on interstate natural gas pipeline facilities. The purpose of the meeting was to gather information and discuss issues relevant to the survey and assessment. Consistent with the President's Regulatory Reinvention Initiative (E.O. 12866), RSPA wanted to explore the Congressional mandate with maximum stakeholder involvement. Toward this end, RSPA sought early participation in the survey and assessment process by holding the public meeting at which participants, including RSPA staff, exchanged views on relevant issues concerning RCVs. The public meeting was used in partial satisfaction of the "survey and assess" portion of the Congressional mandate.

The public meeting was attended by approximately 31 people representing the gas pipeline industry, consultants to the gas pipeline industry, the Gas Research Institute, and RSPA staff. Ten people presented oral comments at the meeting. A sampling of comments made at the meeting is included as Appendix A to this report. There were seven written comments in response to an invitation in the public notice. A summary of each written comment is included as Appendix B to this report. The comments, transcript, and notices in Docket No. RSPA-97-2879 can be accessed at the DOT Dockets Management System's Internet web site.[3]

The notice announcing the public meeting contained eight questions to encourage participants to focus on the issues we believe are the most important. The eight questions and general responses are as follows:

A. What is the potential value of early detection and isolation of a section of pipeline after a failure in terms of enhanced safety and reduced property damage?

One commenter indicated that the potential value of early detection and isolation is the public perception of enhanced safety, whereas another indicated it would reduce the volume of flammable gas being vented. However, most commenters agreed that any consequences from a failure, i.e., casualties or property damage, would occur very soon after the failure and long before RCVs would be effective. In a large diameter pipeline, even if the valves closed instantaneously, it would take some time to blow down the

[3] http://dms.dot.gov

pipeline section involved. An example of this is an approximate blowdown time of 10 minutes for a 5-mile section of a 24-inch pipeline if the failure is near one end (2).

B. What are the technical and economic <u>advantages</u> of installing RCVs?

One commenter indicated a technical advantage is greater reliability if old valves need to be replaced with new ones because of a requirement for the valves to be remotely controlled[4]. The only economic advantage is the value of the gas not lost because RCVs can isolate the ruptured pipeline section faster than manually operated valves.

C. What are the technical and economic <u>disadvantages</u> of installing RCVs?

Comments on technical disadvantages focused on reliability of the technically complex RCV installations, both the hardware and the communications link. The technical difficulties in retrofitting existing valves to provide

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[4]An unknown number of old valves may not be full opening. Replacing them with full opening valves would allow the passage of in-line inspection tools which would be an additional advantage.

remote control, such as matching new valve operators to old valves, was also cited. Commenters stressed past studies which indicate RCVs are not cost beneficial because of the high installation costs of valve actuators and communication links, and the high maintenance costs with no corresponding benefits. One commenter noted that a ten year review of Department of Transportation (DOT) pipeline leak and failure statistics for his company revealed no casualties that could have been prevented by RCVs. This operator estimated the cost of remotely controlling all DOT-required valves in Class 3 and 4 locations would be $40 million with no benefits from reduced casualties over a 10 year period.

D. What states in addition to New Jersey have adopted regulations concerning RCVs on intrastate natural gas pipeline facilities?

Commenters were not aware of any states adopting regulations[5].

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[5]As a result of the pipeline failure in Edison, NJ on March 23, 1994 (2), the New Jersey Board of Public Utilities (BPU) adopted a new set of rules covering the installation, operation, and maintenance of intrastate natural gas pipelines in the state of New Jersey. These rules became effective March 17, 1997.

One of the new BPU rules requires each operator to submit a Sectionalizing Valve Assessment and Emergency Closing Plan for sectionalizing valves in class 3 and class 4 locations. All valves in class 3 and class 4 locations are to be evaluated and prioritized as to the need for installation or retrofitting of a RCV or automatically controlled valve (ACV). Each plan is to include training of appropriate personnel on emergency plans and

E. If RCVs were required in only high risk areas, what would constitute high risk areas and what would be criteria for prioritizing from highest to lowest risk?

Commenters believed operators should determine high risk areas through a risk assessment of their pipelines. The potential magnitude of damage from a pipeline failure because of such factors as population density, pressure, and pipe diameter, and the probability of a pipeline failure due to such factors as subsidence, and proposed contiguous construction activity, should be used as criteria.

F. Document cases where RCVs have malfunctioned causing them to close unexpectedly or to not close when commanded by the dispatcher.

No documented cases of RCV malfunctioning were submitted by commenters.

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procedures. An emergency closing drill that simulates shutting down a selected section of the pipeline is required once each year. Reports of the closing drills are to be submitted to the BPU.

We later surveyed the states to determine if any other states had adopted rules governing sectionalizing valves. None were found as a result of our survey.

G. Document cases where RCVs operated after an accident to reduce the consequences of the accident.

There were no cases documented by commenters. However, one commenter referred to a Gas Research Institute report (2) which indicated, in Appendix B to the report, that an analysis of 80 past failures reported to DOT showed the quick closure of a valve could have prevented an injury in only one incident[6].

H. Provide documentation to support or refute the impression that when the escaping gas from a failed gas pipeline ignites, it normally occurs shortly after the accident, usually less than 10 minutes after the accident.

No concrete documentation was supplied by commenters. There were a number of comments that there are a number on ignition sources at any failure site so that ignition almost always occurs immediately after a failure, or not at all.

3.0 TETCO'S FIELD EVALUATION OF RCV INSTALLATIONS

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[6]Appendix B in the report (2) tabulated a total of 28 fatalities and 116 injuries in the 80 incidents.

As part of the settlement in the compliance case with TETCO involving the failure in Edison, NJ (CPF No. 15102), TETCO offered to fund and perform a number of pipeline safety activities mutually acceptable to OPS and TETCO. TETCO worked with Battelle to develop an RCV project as one of the activities, part of which included a one year field evaluation of the RCVs installed on its pipeline system in New Jersey and other states. The field evaluation included design considerations and commissioning experience as well as actual field experience accumulated over a one year period. TETCO offered this project because it believed it would be useful in responding to the Congressional mandate to study RCVs.

The TETCO experience with installing 90 RCVs on its system is not typical of the gas industry, nor is it to be considered the norm for the industry. It is not meant to be a model for the industry, but was in response to the potential for casualties resulting from catastrophic pipeline failures such as the failure that occurred in Edison, NJ.

The project was monitored by RSPA and a representative from the New Jersey Board of Public Utilities. We attended a briefing in Houston TX on the project on March 25, 1998, which included a tour of TETCO's Gas Control Center. We also toured the Millstone River RCV site in New Jersey on April 14, 1998, and witnessed an activation of a RCV from TETCO's Gas Control center in Houston.

TETCO submitted a field evaluation report (3) received by us on November 4, 1998. The result of the one year field evaluation was that the RCVs were operated approximately 200 times with no valve closure problems when first commanded to close. In addition, there were no actual incidents or false indications to remotely close an RCV-equipped valve. Following are excerpts from the report which we believe are significant enough to be included in this report:

"The total installed costs of the RCV sites installed on the TETCO system ranged from $150,000 for a single mainline valve with an existing valve operator, existing ROW, no permitting problems or road requirements to $500,000 for an eight valve site with significant permitting costs. The average site on the TETCO system with three mainline valves, which have existing valve operators, cost $250,000. These costs represent the range of costs incurred for converting 90 existing valves at 40 sites from local actuation to remote control."

"The average cost of converting a valve to remote control was $125,000 to $150,000 (which included the efficiencies realized at multiple valve sites where site costs could be spread over several valves)."

"There has been no significant impact on direct operating costs as a result of installing remote activation equipment on valves because the maintenance activities for the additional equipment have been absorbed in the function of the technicians that work these sites for other activities. Additional maintenance costs due to RCV equipment are approximately one man-day/year/valve or $20,000 system wide for labor and $15,000 for additional spare parts for 90 RCV equipped valves installed to date via this project. This additional labor is incurred during semi-annual and annual maintenance checks that require cycling the valve and performing sensor and [remote terminal unit] checkouts."

"The design of the RCV upgrade was based on using existing valves and, where practical, systems and hardware currently used by TETCO on other applications. For example, TETCO's prior experience with the Benchmark RTU (remote terminal unit) on gas metering applications was leveraged to apply that system as the controller for the RCVs. Also, sensors and related hardware in use on other TETCO equipment were directly applicable for use on the RCVs."

"Since installation of the RCVs there have been no unplanned valve closures. Unplanned valve closures are considered to be the result of a false valve actuation or a commanded closure in an emergency situation."

"Upgrading valves to RCV status does not impact the time to get people to an incident site. However, the additional capability now available to Gas Control enables more rapid response in evaluating a situation, facilitates more accurate dispatching of personnel, and facilitates isolating an effective section by allowing valves at both ends or multiple sites to be closed quickly and without requiring personnel at each site. Also, in situations that Gas Control can resolve with overwhelming evidence, valve closure can be accomplished before operations personnel access the site.

"Of the approximately 200 valve cycles, the valves closed 100 percent of the time as commanded on the first attempt but failed to reopen upon command in three instances. In one additional instance, a valve failed to close a second time after closing and reopening properly during the first attempt."

"As noted above, there were three cases where valves did not reopen upon command from Gas Control, and one case where a valve failed to close in a second attempt after closing in the first attempt. In all four cases, the problem was the result of a solenoid valve failing to open and provide power gas supply pressure to the operator."

4.0 COST BENEFIT STUDY

A study by Southwest Research Institute (SwRI) (4) for GRI assessed the potential role of RCVs in controlling the blowdown time after a gas pipeline rupture and to evaluate the effects of early isolation on fatalities and injuries. We have used this study as the basis for our determination of the economic feasibility of installing RCVs on interstate natural gas transmission pipelines.

The objective of the study is stated in the report:

> "To evaluate the potential benefit of remotely controlled main line valves in reducing the personal injuries and fatalities associated with pipeline ruptures, and to assess the projected cost of retrofitting existing valves for remote operation."

The SwRI study provides data on which to base a rudimentary analysis of costs versus benefits[7]. For instance, the study concludes that almost no casualties would be prevented by the installation of RCVs. Of a total of 81 incidents studied from 1972 to 1997, virtually all fatalities and injuries occurred at, or very near (within three minutes), of the time of initial rupture, long before the ruptured pipe section would be isolated,

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[7]This degree of analysis is sufficient since a positive benefit to cost ratio based on quantifiable benefits can not be achieved.

even with RCVs installed. The SwRI study concludes that an average of 10 minutes is the time between rupture and initiation of RCV closure (if no on-the-ground confirmation of the rupture by operator personnel is required).

This leaves property damage prevention and the value of gas saved from early valve closure as the only measurable benefits of RCVs. Unfortunately, there are no analyses that compare property damage that occurred before valve closure versus property damage that occurred after valve closure, either with RCVs or manually operated valves installed. Therefore, the value of gas saved because of RCV closure is the only measurable benefit that can be derived from the SwRI study[8].

The SwRI study contains computer simulations of a single and looped pipeline to define the pipeline flow characteristics under rupture condition and arrive at estimated gas loss when RCVs are activated versus when valves are manually closed. On a single pipeline modeled as a 30-inch diameter line, 48 miles long with valves placed every eight (8) miles[9] (a total of seven valves),

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[8]RSPA Edison failure investigators theorize property damage could have been reduced if the ruptured section had been isolated in 10 minutes and blown down in another 10-15 minutes. There is no data to substantiate this theory, however.

[9]Required for a Class Location 3 per 49 CFR 192.179 (a).

operated at a pressure of 1000 psig, the loss of gas after a guillotine line rupture would be 31 MMSCF[10] for RCV closure at 10 minutes and 58 MMSCF for manual valve closure at 40 minutes. The difference would be the gas saved if RCVs were installed or 27 MMSCF (58-31=27). At a gas price of $2.50/MSCF (used in the SwRI study), the savings, and therefore the benefit, would be $67,500. The cost to retrofit the seven valves in this single line to make them RCVs using the cost of $32,332 from the SwRI study, would be $226,324. This is 3.3 times the benefit from the value of gas saved if there was a rupture in the valve section.

Each pipe in the looped pipeline study model (two pipelines in parallel) is the same length, diameter, operating pressure, and valve spacing as the single pipeline model. The only difference is that the line is looped for the 84 miles. At each of the five main line valves between compressor stations[11], there are 10-inch diameter lines connecting the two 30-inch lines and crossover valves to isolate each 30-inch line. The most gas is saved by assuming the crossover valves are operated in the open position, thus both 30-inch diameter lines operate together. The report states the gas loss would be 40 MMSCF for RCV closure at 10

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[10]Million Standard Cubic Feet

[11]There is a valve at each of the two compressor stations.

minutes and 93 MMSCF for manual valve closure at 40 minutes. The difference would be the gas saved if RCVs were installed or 53 MMSCF (93-40=53). At a gas price of $2.50/MSCF (used in the SwRI study), the savings, and therefore the benefit, would be $132,500. The cost to retrofit the fourteen (14) 30-inch diameter valves in this looped line (7 per line) to make them RCVs using the cost of $32,332 from the SwRI study would be $452,648. In addition, there are ten (10) 10-inch crossover valves with a cost to retrofit of $29,395/valve which would be an additional cost of $293,950. The total cost of retrofitting the valves on this model would be $746,598. This is 5.6 times the value of gas saved.

The considerable spread between benefits and costs in just these two models presented in the SwRI study make additional analyses unnecessary.

5.0 ISSUES RAISED BY TECHNICAL PIPELINE SAFETY STANDARDS COMMITTEE

There have been two detailed briefings to the Technical Pipeline

Safety Standards Committee (TPSSC)[12] on the status of work done under this Congressional mandate. There were no issues raised during the first briefing on May 5, 1998. However, there were a number of issues raised during the second briefing on November 5, 1998.

One issue was the public perception that the installation of RCVs increase safety over manually operated valves. The GRI report (4) stated that it takes at least 30 to 40 minutes to close a manually operated valve after a pipeline release whereas a RCV can begin closing in 10 minutes. The same GRI report indicated that a review of pipeline incidents between 1972 and 1997 showed virtually all fatalities and injuries occurred within three minutes of the incident, with most of them occurring at the time of the incident. Therefore, the installation of RCVs would have little or no safety benefit. One committee member remarked that the highest perceived benefit is the public perception about RCVs. This committee recommended that we determine if the public's safety comfort level would be greater if the valves closed in 10 minutes rather than 40 minutes before requiring the spending of a lot of money on RCVs.

[12]The Technical Pipeline Safety Standards Committee is established by statute (49 U.S.C. 60115) to advise the Secretary of Transportation on the technical feasibility, reasonableness, and practicability of all proposed gas pipeline safety standards and all amendments to existing standards.

The issue of delays in closing manually operated valves in populated areas due to traffic congestion was raised in the context of reducing gas loss as it is one of the only measurable advantages of installing RCVs.

The advisory committee discussed other benefits from installing RCVs, other than reducing casualties. Property damage may be reduced, disruption to the public's normal activities may be reduced, and other utilities may be affected. These benefits should be considered if the time to shut in a failed pipeline is reduced. This, of course, reverts to the public perception issue. A member of the public at the TPSSC meeting noted that the public impression of control is an over-riding issue.

There were no solutions advanced at the second TPSSC meeting to deal with the issues raised.

6.0 FINDINGS AND PROPOSAL

6.1 Findings

In this section, we will evaluate findings on the four issues raised in the Congressional mandate, i.e., effectiveness of RCVs, technical feasibility of RCVs, economic feasibility, and reduction of risk with RCVs.

Effectiveness of RCVs

The results from the TETCO one year field evaluation of 90 installed RCVs reported in section 3.0 confirm that RCVs are effective. The valves were operated approximately 200 times with no valve closure problems. They closed the first time when commanded to close 100 percent of the time.

Technical feasibility

The TETCO experience demonstrates that RCVs are technically feasible. TETCO has installed 90 RCVs and has proven that they operate reliably when remotely commanded. There is considerable anecdotal evidence from other operators of successful installations of RCVs, mostly at compressor stations, that confirms their technical feasibility. It is unquestionably feasible to install equipment on manually operated valves to convert them to RCVs because the necessary equipment exists and has been used for years.

Economic feasibility

We can not find that RCVs are economically feasible. The quantifiable costs far outweigh the quantifiable benefits from installing RCVs.

Section 4.0 of this report contains a discussion of the costs versus the benefits. There is a small benefit from reduced casualties because virtually all casualties from a rupture occur before an RVC could be activated. Comparing property damage from ruptures where RCVs are installed versus where manually operated valves are installed is not possible because we are not aware of any studies that have been conducted that compared these damages. Many of the commenters at the public meeting and in writing, reported in section 2.2, indicated the only economic benefit to installing RCVs is the value of gas saved because of quicker isolation of the ruptured section. However, the models used in the SwRI study indicated the cost of installing RCVs to realize the gas saving was 3 to 5 times the value of the gas saved.

The TPSSC commented on issues that impact benefits. These issues included public perception of the benefits from RCVs, disruption to the public's normal activity and the effect on other utilities. Unfortunately, there is no data known to us to quantify these benefits.

Reduction of risk

Installation of RCVs would reduce risk, but the degree of reduction is unknown. The reduction is primarily due to less gas escaping to the atmosphere after a rupture because RCV closure can be in 10 minutes versus 40 minutes (4) if the valves require manual closing, resulting in possible reduced effects, such as property damage. There is some evidence from the NTSB report on the Edison failure (1), that faster valve closure might have allowed firemen to enter the area sooner to extinguish the blazes and might have controlled the spread of the fires to adjacent buildings. However, a quantifiable value can not be placed on this savings to property damage.

6.2 Proposal

We have found that RCVs are effective and technically feasible, and can reduce risk, but are not economically feasible. We have also found that there may be a public perception that RCVs will improve safety and reduce the risk from a ruptured gas pipeline.

We believe there is a role for RCVs in reducing the risk from certain ruptured pipelines and thereby minimizing the consequences of certain gas pipeline ruptures. We are aware of excessive delays operators have experienced manually closing valves following a pipeline rupture. RCVs ensure that a section of pipe can be isolated within a specified time period after the rupture. Once the ruptured section is isolated and no longer receiving additional gas from upstream in the line, any fire would subside as residual gas in the isolated section is burned.

At many locations, there is significant risk as long as gas is being supplied to a rupture site, and operators lack the ability to quickly close existing manual valves. Any fire would be of greater intensity and would have greater potential for damaging surrounding infrastructure if it is constantly replenished with gas. The degree of disruption in heavily populated and commercial areas would be in direct proportion to the duration of the fire. Although we lack data enabling us to quantify these potential consequences, we believe them to be significant nonetheless, and we believe RCVs may provide the best means for addressing them.

Also, by providing a definitive time when the line would be isolated following a rupture, it is possible to determine how and when any fire would die out. This knowledge provides a basis for risk assessment and response planning, important considerations in certain heavily populated or commercial areas, and an important factor in maintaining public confidence.

There are some locations where RCVs may need to be installed to reduce the risk from escaping gas at a failure when a reasonable time to close a manually operated valve can not be established, even though installation of the RCV would not be cost effective. Although we believe a standard requiring time-to-isolate a ruptured pipeline section may be appropriate, we lack sufficient data to consider one. We are therefore hosting a public meeting on Thursday, November 4, at 1:00 p.m., Room 8236, 400 7th Street SW, Washington, DC. We will seek input on information for specifying the time-to-isolate a ruptured pipeline section. Some of the parameters to consider would be -

- Population density
- Vulnerability of the infrastructure
- Environmental consequences
- Accessibility of existing valves based on changing conditions such as weather and traffic
- Valve spacing

- Operational parameters (such as pipe diameter and operating pressure)

7.0 REFERENCES

(1) National Transportation Safety Board, "Texas Eastern Transmission Corporation Natural Gas Pipeline Explosion and Fire, Edison, New Jersey, March 23, 1994," PB95-916501, NTSB/PAR-95/01, January 18, 1995.

(2) C. R. Sparks, et al., (Southwest Research Institute), "Remote and Automatic Main Line Valve Technology Assessment," Final Report to Gas Research Institute, Report No. GRI-95/0101, July 1995.

(3) David W. Detty, P.E., (Battelle Memorial Institute), " Texas Eastern Transmission Corporation, Remote Control Valves Field Evaluation Report, October, 1998."

(4) C. R. Sparks, et al., (Southwest Research Institute), "Cost Benefit Study of Remote controlled Main Line Valves," Final Report to Gas Research Institute, Report No. GRI-98/0076, May 1998.

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Public Meeting on 10/30/97

Adams Mark Hotel, Houston

Summary of Remarks from Transcript

! Tetco has had good experience with ACVs using "threshold pressure change," don't disallow ACVs (Drake, p.9)

! In NTSB reports where RCVs recommended, they wouldn't have significantly mitigated property damage or injuries (Richardson, p.13)

! Question of RCVs deals with economics and operating aspects, has little to do with safety or property damage (Richardson, p.15)

! Closing valves faster with average spacing of 20 miles would not significantly reduce damage because average vent time is an hour or so (Steinbauer, p.17)

! Hope any rule issued would be a design rule, couldn't justify new RCVs much less refitting existing valves (Richardson, p.20)

! Only savings is reducing time that gas blows and that can be calculated (Richardson, p.22)

- ! Command or communication system is the most unreliable part of RCVs (Richardson, p.23)

- ! The issue of closing multi-line systems must be addressed (Drake, p.25)

- ! The real issue on the consequence side is public perception (Drake, p.27)

- ! On the cost side: failures, ignition, majority of damage, and protecting lots of people will not be stopped by RCVs (Drake, p.28)

- ! Must consider what the industry is doing now, since it's successful (Deleon, p.31)

- ! For CGS, back of envelope calculation, retrofitting valves in Class 3 & 4 locations, $40 million cost & $2 million benefit (Burney, p.32)

- ! For SoCal, retrofitting valves on 4,000 miles in Class 3 & 4 location, cost would be $70 million (Mosinskis, p.33)

- Placement of RCVs should be based on RM rather than across-the-board in a certain class location (Drake, p.39)

- For PSE&G of NJ, no feedback from the commission on the adequacy of our valve assessment required by state regulations (McClenahan, p.47)

- Dispatcher's decision to close valve must be on a case-by-case basis, not a detailed procedure (Mosinskis, p.51)

- The industry, industry associations, or GRI could develop guidelines for dispatchers to use (Burnley, p.58)

B-1

Summary of Seven Written Comments to

Docket No. RSPA-97-2879; Notice 1

Questar Regulated Services Company

! Parent company of Mountain Fuel Supply & Questar Pipeline Company. Mountain Fuel has 625,000 customers in UT, ID, and WY. Questar Pipeline operates in CO, UT, and WY. Together operate 2950 miles of transmission, 10,000 miles of mains, 8285 miles of services.

! The decision to install RCVs (or ACVs) should be left up to the operator using risk assessment providing a more flexible approach.

! An operator may decide ACVs (or "line-break" valves) are a better fit for it's system.

! Criteria could include densely populated areas (CL 3 &4), response time due to remote locations, ESAs, or other high risk area identified by the operator.

! Mandating RCVs would require Questar to replace existing ACVs at substantial expense without incremental benefits.

Columbia Gas Transmission

- Columbia gas system has 16,300 miles of transmission lines.

- Installing RCVs won't significantly lower the potential consequences associated with ruptures, prevent ruptures, eliminate blowing gas, or eliminate fires.

- The industry currently has no criteria for the placement of RCVs; In all Cl 3 & 4 locations is too broad.

- The only potential value is the public perception of enhanced safety even though the majority of damage would occur before the valve was closed.

- The only advantage is limiting gas loss if and when a rupture occurs.

- Many disadvantages including: More complex, requires SCADA and human intervention, power or communication failure could render a RCV inoperable, and retrofitting many different valve designs could be technically difficult.

- Economic disadvantages: From a review of Columbia's accident data over 10 years, no deaths or injuries would have been prevented by RCVs. To require RCVs on sectionalizing block valves in Cl 3 & 4 locations on Columbia is estimated to cost $40 million, with $0 benefits.

- High risk areas determined by population density, proximity to the pipeline, operating conditions, calculated radiant heat, terrain, predominate building construction and materials.

- One documented case: An incident over Mississippi River on Aug. 24, 1993, an ACV closed on one side of the river, but the ACV on the other side did not.

Pacific Gas and Electric Company

- Has over 3 million gas customers in CA.

- Have no objection to installing RCVs, have found them reliable, install them when upgrading existing major control stations or installing new stations.

- Objects to GRI finding of reliability of ACVs. PG&E has found that the sensitivity of the detection system must be set so low as to miss some line breaks, in their experience.

! Safety would be enhanced by reducing the volume of flammable gas released.

! Major technical advantage by isolating section quickly without dispatching personnel and knowledge of valve status using SCADA.

! Major economic advantages are minimizing company liability, and potential for minimizing gas customer outage by quickly isolating section and providing alternate gas supply.

! Main disadvantages is high cost and potential for inadvertent shutdown.

! No documented cases, but PG&E dispatchers have experienced both malfunctions and cases where the valves closed on demand.

! One can assume that if ignition occurs, it will occur a few seconds after rupture.

Dayton Power and Light Company

! Has 300,000 gas customers, both intrastate transmission and distribution pipelines.

! Supports limited use of RCVs and has installed them to alleviate manual, hand-cranking of valves; *however*, field verification is essential before remotely activating valve.

! Definition for "high risk area" would be inconsistent the established class location scheme; it would be different for each operator.

! Should be evaluated in conjunction with the consistent application of accepted risk management principles.

Transco

! Thinks the use of RCVs should be part of an operator's risk management strategy.

! Problems with installing RCVs:

- Today's technology does not differentiate to a high degree of accuracy between transient operating pressures and ruptures.
- Blowdown times are often one hour or more even with immediate closure.
- With ignition time of 2-10 minutes, plume ignition will not be affected.
- Cost will be high for operators with multi-line systems.

Texas Gas Transmission

! Operates 5,700 miles of 2" - 42" pipelines.

! Retrofitting existing valves very expensive. Not so on new installations.

(no other new comments from those made by previous commenters.)

Enron Gas Pipeline Group

! Group includes FL Gas Trans., Northern Natural, Transwestern, Houston P.L. Co., Black Marlin P.L. Co., & LA Resources Co. which together operate 27,000 miles of pipe.

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! Routinely review specifics of incidents. Conclusion from reviews is that RCVs, if installed, would not have contributed to public safety or the reduction of property damage.

! Decision should be left up to operator.

(no other new comments from those made by previous commenters.)