Docket No. SA-534

Exhibit No. 2-DU

NATIONAL TRANSPORTATION SAFETY BOARD

Washington, D.C.

PGE COMMENTS TO PHMSA-RSPA

(37 Pages)

NTSB PGE Comment

PHMSA-RSPA-1997-2879-0011

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December 1, 1999

Docket Facility
U.S. Department of Transportation
Room PL-401,
400 Seventh Street
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SUBJECT: Docket No. RSPA-97-2879

In response to RSPA's Request for Comment on Pipeline Safety: Rapid Isolation of Ruptured Sections of Gas Transmission Pipelines (DOT Docket No. RSPA-97-2879), Pacific Gas & Electric Company (PG&E) would like to provide the following comments for establishing time limits for isolation of ruptured pipelines. PG&E is an investor-own utility providing natural gas and electric service to more than 12 million people in Northern and Central California. PG&E has over 5,600 miles of intrastate gas transmission pipelines.

Prior to addressing the 6 questions listed in the Federal Register notice, we would like to provide some general comments regarding establishment of time limits for isolating a ruptured pipeline section. Prescriptive regulation, such as being proposed, in our opinion is not the answer to improving public, environmental, or equipment safety. The proposed regulation deals more with minimizing consequences should a failure occur. We are more supportive of looking at all the risk components of a given pipeline section, including likelihood of failure and consequences of failure, and targeting the risk reduction activity that provides the highest value. The focus should be on preventing the failure, and not managing the consequences. The regulatory framework should support utilities spending dollars to prevent failures altogether, versus managing the consequences that occur.

The following are response to the 6 questions in your request:

1) What are the variables that should be considered in establishing a time-to-isolate standard? As an example, one variable could be the time for gas contained in the

ruptured section to burn, if there is a fire, after the section is isolated by closing valves on each side of the rupture.

- *Risk to public.*
- *Risk to property.*

- *Risk to company personnel.*
- *Volume of gas contained in the isolated section.*
- *Number of feeds into zone affected by the rupture.*

2) Should an operator's time-to-isolate a ruptured pipeline section be the same in each class location? If not, what difference should there be in the time-to-isolate for each of the four class locations?

No. It makes sense to factor the Class Location (i.e., population density) into the determination of time-to-isolate a ruptured pipeline. A more densely populated area should require a shorter time-to-isolate the ruptured pipeline.

Possibly, Class 1 & 2 and Class 3 & 4 can be grouped together. Class 3 & 4 locations should be more accessible because of better surface roads and generally closer proximity to maintenance bases than Class 1 &2 locations.

3) Should the definitions for class location in 49CFR192 be revised to provide for more stringent requirements in areas where there would be more significant consequences from a ruptured transmission pipeline where the escaping gas caught fire? Examples of areas of more significant consequences are commercial areas and apartment buildings with high population concentrations.

No. 49CFR Part 192 already provides for more stringent requirements (e.g., closer spacing of valves, lower design factors) in areas with higher Class Location designations. These Class Location designations generally correspond to areas where consequences of rupture are greater.

3a) What are other examples of areas subject to more significant consequences from a ruptured transmission pipeline where the escaping gas caught fire?

Close proximity to other utility structures, such as , electric transmission and distribution lines, oil pipelines, and other gas lines; also, gas piping on bridge structures.

3b) Should areas of more significant consequences be included in the definition for Class 3 and 4 locations or should separate sub-class locations be established for these areas?

No. Utilities already encounter difficulties in determining Class Location *boundaries and in determining when there is a change to the four existing Class Locations. Adding sub-classes would be more confusing and would make it difficult for operators to accurately and consistently identify Class Location boundaries. Also, the additional patrols, analysis and documentation which would be required to ensure proper identification of these sub-classes would have questionable beneficial value.*

4) Should the transmission line valve spacing requirements in 49CFR192.179 be reduced for Class 3 and 4 locations of highest consequences? If not, why not? *No. When the class locations were originally established, both the transmission valve spacing and the pipeline design factor were directly a function of class location. The higher populated areas (i.e., Class 3 and 4) require closer valve spacing and higher pipe safety factors. Mandating reduced valve spacing requirements for Class 3 & 4 locations of highest consequence will require additional expenditures for valve installation, as well as, on-going monitoring for changes in these subclass locations.*

5) What should be the maximum time for closing valves to isolate a rupture valve section? Should RCVs be installed to assure the closing time is not exceeded?

The specific value must be determined from studying the time required for each activity which must occur between the time of a pipeline rupture and the final isolation of the ruptured zone from any gas source. These activities include: notification of the operator, evaluation of data to confirm rupture location and system impact, evacuation of the affected area, dispatch of personnel or signal to isolate gas, and operation of the valve(s) at the required site(s). We recommend 1 hour to isolate Class 3 & 4 and 2 hours in Class 1 & 2.

The maximum time should not be arbitrarily set too low requiring RCVs to be installed in most instances. As noted in your September 1999 report on Remotely Controlled Valve on Interstate Natural Gas Pipelines, the cost of installation of RCVs is several times the cost of the expected value of gas saved, which is the only quantifiable economical benefit of the RCVs. Any expected injuries/property damage would have occurred within the first few minutes of the rupture, long before the RCV would have been activated.

Furthermore, the safety of the public and emergency personnel may be compromised with the use of RCVs. Our first priority to make the rupture site safe by evacuating people from the impacted area. Potentially, a quick shut down of gas flow by an RCV may give the public a false sense of security. An RCV that fails to completely close or leaks may allow a combustible mixture of gas to build up at the rupture site. Members of the public or emergency personnel entering the hazardous area without the utility first checking for combustible vapor would be *subjected to potential injuries and/or fatalities.*

6) Should there be a tiered approach to establishing a time-to-isolate standard, e.g., less time in Class 4 than in Class 3 locations?

No. See responses to items 2 and 5 above.

Thank you for the opportunity to comment.

Sincerely,

Richard Arita

Richard Arita
Senior Gas Engineer, System Integrity
Gas System Maintenance & Technical Support

NTSB PGE Comment

PHMSA-RSPA-2000-7666-0021

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June 21, 2000

Docket Facility
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SUBJECT: Docket No. RSPA-99-6355

Pacific Gas and Electric Company (PG&E) would like to provide the following comments in response to RSPA's Request for Comment on Enhanced Safety and Environmental Protection for Gas Transmission and Hazardous Liquid Pipelines in High Consequence Areas (DOT Docket No. RSPA-99-6355; Notice 1). PG&E is an investor-owned utility providing natural gas and electric service to more than 12 million people in Northern and Central California. PG&E has over 5,600 miles of intrastate gas transmission pipelines.

PG&E supports efforts that will further assure the public about the safety and integrity of natural gas pipelines and will work with OPS and state regulators in this new initiative. We understand that OPS is seeking to validate each operator's systematic process for evaluating risks to pipeline systems in high consequence areas and before addressing the specific questions listed in the Federal Register notice, would like to take this opportunity to provide a brief overview of the approach taken by PG&E.

In addition to standards which implement pipeline safety regulations, PG&E utilizes a Geographic Information System (GIS) and a Pipeline Risk Management Program to continually improve system-wide operations and safety. PG&E's GIS contains the geographical location, pipe specifications, and the operating condition of its transmission pipelines. It also contains all the field reports of new construction, pipe condition and leaks. Our Pipeline Risk Management Program assesses the likelihood of failure due to mechanisms such as: third party damage, corrosion, and ground movement (including seismic hazards and major water crossings). It also assesses the consequences of failure in terms of impacts to the public, the environment, and to our business.

In the Federal Register notice, OPS has put out the following key elements for the process it envisions:

- The need for pipeline-specific assessments in determining the need for additional preventive and mitigative activities.
- The need to assess all risk factors and risk reduction activities in an integrated manner.
- The need for increased assurance that high consequence areas are being protected.

Keeping these key elements in mind, the following are PG&E's responses to selected questions asked under each of the process steps defined by OPS.

1. Identifying and Locating High Consequence Areas

a. How should "high consequence" areas be defined?

We support a definition which takes into account population density, environmental impact, and service impact. Examples of areas PG&E would consider to be high consequence areas are Class 4 locations, hospitals, schools, places of public assembly, apartment complexes, railroads, highways, airports, commercial/industrial buildings, navigable waterways, parks, and recreation areas, etc.

b. Should the operator or OPS be responsible for identifying the location of high consequence areas?

Due to the complexity of the issue, OPS should set general guidelines and require the operator to be responsible for identifying the location of high consequence areas.

e. What process should OPS or the industry use to ensure that the identified high consequence areas continue to reflect current conditions along the pipeline (e.g., population expansion, new information on environmental resources)?

Currently Code requires operators to monitor and record new construction and other changes occurring along the pipeline. This information is generally obtained from regularly scheduled patrols (foot and aerial), during development of drawings for new construction, and from special field surveys. PG&E posts this information routinely into GIS and utilizes that system to verify current conditions along the pipeline.

2. Identifying Affected Pipeline Segments

a. Does adequate data exist for operators to reliably ascertain the specific pipeline segments that could affect "high consequence" areas?

We believe adequate information exists. However, depending upon how "high consequence" areas are defined, operators may need to collect more data to accomplish this step.

b. Should pipeline segments near, but not within, high consequence areas also be examined for possible impact?

In identifying pipeline segments that could affect "high consequence" areas, we suggest that factors contributing to the likelihood of failure and/or factors impacting the consequences of failure of the high consequence line be considered. In short, we do not want any pipeline to fail, especially if it has any secondary impact on the high consequence area.

3. Inspecting and Assessing the Condition of the Affected Segme nts

a. Are the current industry standards sufficient for pipelines in "high consequence" areas?

Based on our experience, PG&E believes that current Code requirements and industry standards are sufficient, provided they are diligently applied by the pipeline operator. We also believe current requirements can, in certain instance, be overly conservative.

b. What is the current capability of smart pigs to find prior mechanical damage and other defects?

Regulations should not require operators to use smart pigs. At the present time, when a condition impacting pipeline integrity and public safety is identified by routine or non-routine maintenance, the pipeline operator is allowed to review the pipeline condition and choose the most cost-effective method(s) to assess/restore the structural integrity. The methods available to the operator could include smart pigging, if feasible given the pipeline geometry and other factors. This flexibility provided to the operator should not be withdrawn in favor of a mandate for use of smart pigs.

PG&E views smart pigs as one available tool for the assessment of pipeline condition. While smart pig technology has been utilized by PG&E, and current smart pig products reliably provide valuable information regarding pipeline corrosion damage, we can often determine critical pipeline conditions through other less costly means.

c. What alternatives to internal inspection can provide equivalent information on pipeline condition?

There are many other pipeline inspection methods available today. Each method identifies limited characteristic(s) of a pipeline and each method has an associated level of effectiveness. Examples of some other inspection methods include:

- *Video inspection which can detect interior corrosion, ovalization, buckles and dents,*
- *Close interval CP inspection which can ensure proper cathodic protection on pipelines*
- *X-ray which can detect defects in girth welds*

PG&E has found smart pigs to be effective at detecting pipeline corrosion. While smart pigs may be represented by manufacturers to be effective in many other measurements, our experience indicates that measurement of other pipeline characteristics by today's smart pig is both unreliable and less exact than other technologies.

d. How recently should a line have been pigged to provide reliable data for this step? What factors should be considered in making this determination (recent construction activity, cathodic protection system performance, interference from foreign line crossings, etc.)?

Many factors must be considered when establishing re-inspection intervals, including an analysis of the previous data relative to potential damage mechanism that have been identified. Re-inspection intervals should be left to the operator to establish.

e. How soon should the condition of a line be assessed after determining that it could impact a high consequence area?

After an operator has identified that a pipeline segment could impact a "high consequence" area, a comprehensive plan to assess the pipeline conditions should be immediately developed. The plan should include a historical review of existing data, assessment criteria, inspection method(s), implementation schedule, and cost. The plan should be implemented for the affected pipeline segment as soon as *practical, but the schedule will depend on a number of factors, including permit requirements, equipment availability, and operating requirements. For this reason PG&E believes operators should be allowed to set their own schedule .*

f. What criteria should be used to identify anomalies that require further investigation?

We believe current industry standards are sufficient and should continue to be used as the criteria for identifying and evaluating anomalies.

g. What is the appropriate period between pig runs for high consequence areas? (Should this period be based on pipeline-specific conditions impacting the likelihood of corrosion or mechanical damage?)

Again, PG&E supports allowing operators the flexibility to use the inspection tool that is the most effective for the condition being evaluated. We support and encourage the adoption of a risk management approach to continually assess pipeline conditions and to determine appropriate inspection frequencies for specific pipeline segments. This approach would consider a number of factors including, corrosion, likelihood of third party damage, and ground movement.

h. Should OPS specify minimum performance criteria for internal inspection tools? If so, what should those criteria be?

The criteria should be developed collectively by OPS, operators and vendors.

4. Assessing the Need for Additional Preventative or Mitigative Actions

a. What structured assessment and decision processes could operators use to perform this step?

Operators should establish a comprehensive, integrated, segment-specific assessment program. We believe PG&E's Pipeline Risk Management Program is a good example of such a structured assessment.

b. What should be the criteria for deciding whether additional actions by the operator are required?

In determining additional actions, we recommend that actions be based on two factors: 1) Risk ranking - according to the Risk Management Program's evaluation and 2) a benefits to cost evaluation.

5. Remedying and Repairing the Affected Segments as Necessary

a. Should current industry standards be used as the repair criteria, or do other methodologies exist or need to be developed for pipelines in high consequence areas?

PG&E believes the current industry standards are sufficient, but is supportive of new technology developments and Code improvements.

b. What is the status of the current rulemaking to allow alternative repair techniques?

We welcome the recently issued final rule on Gas and Hazardous Pipeline Repair (RSPA-98-4733). The new rule will allow alternative repair techniques and encourage new repair technologies.

c. After an operator identifies anomalies requiring repair, how much time should be allowed in which to complete the repair work?

It will depend on the characteristics of the anomaly. If it has safety related consequences, it should be repaired as soon as conditions allow. If it has little or no impact on public or employee safety, the environment, or service reliability, the operator should be allowed to plan and schedule repair within a year.

6. Implementing and Monitoring Other Cost-Effective Risk Control Activities

a. How can operators monitor the effectiveness of risk control activities?

An annual report should be established that documents the risk management efforts and analyzes the incidents that have occurred. By analyzing incidents, Risk Management Program algorithms and the mitigation efforts taken to reduce risk can be validated and refined.

b. How would integrating an implementation schedule into normal operator maintenance schedules or budget cycles affect the cost of implementing these activities?

Integrating an implementation schedule into normal operator maintenance schedules or budget cycles will definitely save time and cost over treating it as a separate program.

7. Documenting Inspections, Assessments, and Actions

What would be the expected costs and labor burdens of these documentation requirements?

PG&E supports requiring operators to have thorough, accountable records of all steps identified in the operator's pipeline integrity and risk management program. If the process for high consequence areas outlined in this Federal Register notice is integrated into normal operator maintenance schedules, the cost and labor burden to meet these documentation requirements should be minimal.

8. OPS Reviews Operator Compliance

a. How can OPS ensure consistency of review across all companies?

We believe OPS or state regulators, as appropriate, should conduct an initial review of each operator's risk management or pipeline integrity programs and follow-up with regularly scheduled reviews, possibly to coincide with normal auditing schedules. The goal of these reviews should be to establish a cooperative working relationship between the operator and the regulating authority to ensure an effective and proactive safety program.

b. What review protocols or criteria will OPS use to evaluate the effectiveness of an operator's assessment and decision-making processes?

The effectiveness of an operator's risk management program should be measured by the safety performance of the pipelines by comparing with the operator's previous records and also industry statistics.

Thank you for the opportunity to comment.

Sincerely,

Chih-Hung Lee

Chih-Hung Lee
Senior Gas Engineer, System Integrity

Gas System Maintenance & Technical Support

NTSB PGE Comment

PHMSA-RSPA-2000-7666-0089

Department of Transportation
Research and Special Programs Administration
[Docket No. RSPA-00-7666; Notice 2]
Pipeline Safety: Pipeline Integrity Management in High Consequence Areas
Pacific Gas and Electric Company Comments

Ms. Stacey L. Gerard
Associate Administrator for Pipeline Safety
C/o Dockets Facility
US Department of Transportation, Room PL-401
400 Seventh Street, SW
Washington, DC 20590-0001

Dear Ms. Gerard:

Pacific Gas and Electric Company appreciates the opportunity to comment on the components of this "hypothesis". As the Utility subsidiary of PG&E Corporation that provides natural gas and electric services to northern and central California, we operate 6300 miles of natural gas transmission pipelines throughout California.

As you are aware, Pacific Gas and Electric Company has already begun a Risk Management program to improve the safety and reliability of our pipelines. We have been an active participant working with NAPSR to establish risk management processes, working with industry and regulators to validate the effectiveness of ECDA, and working through ASME to develop an integrity management appendix to B31.8.

The following pages comprise our initial comments regarding the "hypothesis". We hope our feedback and our experiences with implementing integrity assessments will help OPS develop a rule that effectively improves safety and awareness about the integrity of pipeline facilities. When the rule is proposed, Pacific Gas and Electric Company will provide more detailed comments.

Sincerely,

Alan Eastman
Manager – System Integrity

Scope of an eventual gas integrity management rule
Our current thinking is that any standards we eventually propose on gas integrity management will apply to all gas transmission lines and support equipment, including lines transporting petroleum gas, hydrogen, and other gas products covered under Part 192.

Pacific Gas and Electric Company believes the integrity management rule should only apply to transmission lines operating at or above 20%SMYS in high consequence areas. The pipelines with small diameters, low pressure and operating below 20% SMYS and the lines not operating in high consequence areas pose a much lower relative risk and should be excluded from consideration in the rulemaking.

Elements of an eventual gas integrity management rule
We believe that to fulfill our objectives, any rule that we propose on integrity management programs for gas operators would need to address the following seven elements. We used similar elements in developing the liquid integrity management rules. Our treatment of these elements will be based on certain hypotheses that are discussed below. We welcome comment about these elements and hypotheses.

1. Define the areas where the potential consequences of a gas pipeline accident may be significant or may do considerable harm to people and their property. (We are calling these high consequence areas).

- Data from sites where gas pipelines have ruptured and exploded have shown that the range of impact of such explosions is limited. Therefore, the area in which near by residents may be harmed or their property damaged by potential pipeline ruptures can be mathematically modeled as a function of the physical size of the pipeline and the material being transported (typically, but not exclusively, natural gas).

- Because gas pipeline operators are required to maintain data on the number of buildings within 660 feet of their pipelines, the definition of potentially high consequence areas where additional integrity assurance measures are needed should incorporate these data.
Pacific Gas and Electric Company concurs with the use of structure data but notes that once a class location reaches '3', the structure data is no longer accumulated. Therefore, the information in Class 3 areas may not be current.

- The range of impact from the rupture and explosion of very large diameter (greater than 36 inches) high pressure (greater than 1000 psi) gas pipelines is greater than the 660 feet currently used in the regulations.
Pacific Gas and Electric Company concurs with the use of the C-FER model for pipelines whose impact is larger than 660'. However, Pacific Gas and Electric Company recognizes that there are other more extensive models that should be allowed if a Company chooses to perform a more extensive evaluation of the impact.

- Special consideration must be given to protect people living or working near gas pipelines who would have difficulty evacuating the area quickly (e.g., schools, hospitals, nursing homes, and prisons).
Pacific Gas and Electric Company Supports and would include day-care facilities with more than 25 persons.

- Because of the relatively small radius of impact of a gas pipeline rupture and subsequent explosion, and the behavior of gas products, environmental consequences are expected to be limited. At this time, OPS has little information that would indicate the definition of high consequence areas near gas pipelines should include environmental factors.
Pacific Gas and Electric Company concurs that environmental consequences are generally low and should not be a part of the rule.

Given that pipeline operators maintain extensive data on the distribution of people near their pipelines, OPS intends for operators to use these data, together with a narrative definition of a high consequence area (that OPS will define), to identify the specific locations of high consequence areas. For OPS to map high consequence areas for public and regulatory use, operators will have to provide data (hard copy or digital) on the location of people living near their pipelines as an attribute associated with the pipeline geospatial features. For any operator not able to provide these data, OPS would, instead, rely on census data to complete the maps of high consequence areas to be used for gas integrity purposes. OPS is using this data to map the high consequence areas defined in the liquid integrity management rule.

Pacific Gas and Electric Company notes that current data may not be available. If the location has been Class 3 for a long period of time, new structures may not be known. Pacific Gas and Electric Company would propose that operators be allowed to use 3rd party data sources that address match the locations of High Consequence structures and use Census data to determine if housing density could reach or exceed 25 structures within the circle circumscribed by the C-FER.

2. Identify and evaluate the threats to pipeline integrity in each area of potentially high consequences.

- Effective integrity management begins with a comprehensive threat-by-threat analysis. One approach divides potential threats to pipeline integrity into three categories: time dependent (including internal corrosion, external corrosion, and stress corrosion cracking); static or resident (including defects introduced during fabrication of the pipe or construction of the pipeline); and random (including third party damage and outside force damage). In addition, human error can influence any or all of these threats.
  Pacific Gas and Electric Company concurs with the need to evaluate the three categories of threats. However, Pacific Gas and Electric Company believes that existing rules, which include the recent "Operator Qualifications" adequately addresses human error.

- Identification and evaluation of the significance of threats to pipeline integrity must involve the integration of numerous risk factors. Such risk factors include, but are not limited to, pipe characteristics (e.g., wall thickness, coating material and coating condition; pipe toughness; pipe strength; pipe fabrication technique; pipe elevation profile); internal and external environmental factors (e.g., soil moisture content and acidity, gas operating temperature and moisture content); operating and leak history (e.g., pipe failure history, past upset conditions that have introduced moisture into the gas); land use (e.g., active farming, commercial construction, residential construction); protection history (e.g., corrosion protection data, history of third party hits and near misses, effectiveness of local One Call systems); and the degree of certainty about the current condition of the pipeline (e.g., age of the pipe, completeness of integrity-related records, available inspection data).
  Pacific Gas and Electric Company concurs

- Pipelines having threats that represent higher risks should generally be assessed sooner than those with threats that represent lower risk.
  Pacific Gas and Electric Company concurs as long as factors such as economy of scale, construction difficulties, long-lead time materials, etc. are allowed to alter the schedule. For instance, a pipeline may have 3 HCAs, one high risk and two low risk. Economy of scale may dictate smart pigging all three HCAs earlier than medium risk section on another pipeline. Pacific Gas and Electric Company is currently utilizing risk assessments on every mile of its system to prioritize integrity assessments.

- Numerous studies and analyses on leak vs. rupture thresholds of natural gas pipelines have shown that pipelines that operate at a stress level less than 30% SMYS fail differently (i.e., leak rather than rupture) from those operating at higher stress. Therefore, different integrity assurance techniques may be appropriate.
  Pacific Gas and Electric Company concurs and would recommend utilizing increased leak patrol frequencies to minimize the leak threat

3. Select the assessment technologies best suited to effectively determine the susceptibility to failure of each pipe segment that could affect an area of potentially high consequences.

- An integrity baseline needs to be established for all pipe segments that could affect an area of potentially high consequences. An operator will need to evaluate the entire range of threats to each pipeline segment's integrity by analyzing all available information about the pipeline segment and consequences of a failure on a high consequence area. Based on the type of threat or threats facing a pipeline segment, an operator will choose an appropriate assessment method or methods to assess (i.e., inspect or test) each segment to determine potential problems.

  Pacific Gas and Electric Company concurs and believes that a 10-year time frame would be reasonable for establishing a baseline.

- Time dependent threats will also require periodic inspection to characterize changes in their significance.

  Pacific Gas and Electric Company concurs and supports current efforts in B31.8 to define intervals

- Acceptable technologies for assessing integrity include in-line inspection, pressure testing and direct assessment. None of these technologies individually is fully capable of characterizing all potential threats to pipeline integrity. **Pacific Gas and Electric Company Concurs**.

- OPS is co-sponsoring with industry and state agencies an evaluation of direct assessment technology to determine the conditions under which direct assessment is effective in assessing external corrosion. The validity of direct assessment in assessing other threats (e.g., internal corrosion, stress corrosion cracking) is also being explored.

- Static threats will require pressure testing at some time during the life of the pipeline. If significant cyclic stress, such as that caused by large pressure fluctuations, is present, then pressure testing, or an equivalent technology, will be required periodically throughout the life of the pipeline.

  Pacific Gas and Electric Company believes that for most situations pressure testing is the best integrity verification for pipelines operating over 30% SMYS with joint efficiencies less than 1.0. However, the option of using other integrity verification tools should be allowed. For all other pipelines, particularly pipelines operating below 30%, Pacific Gas and Electric Company believes operating history validates the material strength and pressure testing in not needed.

- Random threats will require the use of two parallel integrity management approaches. The vast majority (over 90%) of ruptures caused by random threats occur at the time when the threat is imminent (e.g., when the excavator hits the pipeline). Therefore, the use of risk management practices (or technologies) to prevent damage or to immediately identify the potential for damage would be more effective than looking for evidence of past damage. Secondly, since some random threats do not result in immediate pipeline rupture, technologies that look for evidence of past damage after the threat has occurred should be focused in areas where delayed failure is most likely.

- Threats related to human error will be addressed largely, but not completely, through the new Operator Qualification Rule. An integrity management rule may need to address more specific problems.

Pacific Gas and Electric Company concurs that human error is already adequately addressed

4. Determine time frames to conduct a baseline integrity assessment and to make any needed repair using a graded (tiered) approach where assessment and repair are prioritized according to risk.

- The time frame for conducting the baseline assessment should be based on a graded or tiered approach where pipeline segments are prioritized for assessment according to the level of risk they pose. Thus, highest risk segments would be scheduled for assessment first, lowest risk last. A schedule for taking remedial action on the pipeline segment after the assessment would also be based on risk factors.

Pacific Gas and Electric Company supports the ASME B31.8 time frames.

- The time frame for conducting the baseline assessment should, among other factors, consider the impact on gas supply to residents. This could also be a factor in determining if a variance from the required time frame is warranted.

Pacific Gas and Electric Company concurs

- The sequence in which the segments are prioritized for assessment should be determined by considering information such as, how much pipe is in areas of potentially high consequences, which of these pipe segments represent the highest risk, which threats for these segments represent significant risks, how much time will be needed to develop the infrastructure to perform the required assessments (e.g., validate the required assessment technologies, develop consensus standards for the application of these technologies, expand the industry capability to deploy and effectively use these technologies to assess pipeline integrity). If the assessment finds potential problems, the schedule for making the repairs would also be based on risk factors.
  Pacific Gas and Electric Company concurs but believes that construction difficulties or economies of scale may move pipeline segments up or down the schedule

5. Identify and implement additional preventive and mitigative measures appropriate to manage significant threats.

- Assuring a pipeline's integrity requires more than simple periodic inspection of the pipe. Most threats, including passive threats such as third party damage, require active management to prevent challenges to integrity. Therefore, active integrity management practices are necessary. Some operators already go beyond the current pipeline safety regulations by implementing integrity management practices such as ground displacement surveys, soil corrosivity analysis, gas sampling and sampling and analysis of liquid removed from pipelines at low points.

Pacific Gas and Electric Company concurs

- Preventive and mitigative measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety. Such actions may include damage prevention practices, better monitoring of cathodic protection, establishing shorter inspection intervals, installing Remote Control Valves (RCVs) or Automatic Shut-Off Valves (ASVs) on pipeline segments. Some operators, particularly hydrogen pipeline operators, have voluntarily installed ASVs on their pipelines at short intervals as a mitigative measure.

Pacific Gas and Electric Company concurs.

6. Continually evaluate and reassess at the specified interval each pipeline segment that could affect an area of potentially high consequences using a risk-based approach. The evaluation considers the information the operator has about the entire pipeline to determine what might be relevant to the pipeline segment.

- Managing a pipeline's integrity requires periodic reassessment of the pipeline. The time frame appropriate for this reassessment depends on numerous factors. In the current class location change regulation, gas pipeline operators are required to replace pipe segments with thicker-walled or stronger pipe (or decrease pressure) as the near-by population increases above threshold levels. This requirement for thicker-walled or stronger pipe in areas of higher population might indicate that a longer reassessment interval would be appropriate where corrosion is the dominant threat

- If critical risk factor data are not available to support evaluation of risks, then the reassessment interval should be appropriately shortened to reflect that absence of knowledge.
- If an operator has developed a comprehensive picture of past and anticipated threats, including detailed information on risk factors and records of multiple assessments carried out over several years, the operator might be able to justify a longer reassessment interval.
- The periodic evaluation is based on an information analysis of the entire pipeline.

7. Monitor the effectiveness of the management process designed to provide additional assurance of integrity in areas where the consequences of potential pipeline accidents are greatest.

- Measures can be developed to track actual integrity performance as well as to determine the value of assessment and repair activities.

Pacific Gas and Electric Company concurs and supports the metrics being developed for B31.8 Integrity Mgmt Appendix.

- Application of integrity management technologies that exceed current regulations is cost effective because many companies have made the decision to implement such programs.

Pacific Gas and Electric Company concurs that integrity management is cost effective. However, the type and complexity of the pipeline system will dictate if a specific technology is cost effective or even possible. For this reason, it is important that a variety of integrity management technologies by available for use.

Consideration of Impact on Gas Supply

Recent events, particularly in California and the Midwest, have highlighted the limitations of energy supply in certain parts of the country. Assessing pipelines using any of the technologies being considered may result in a restricted gas supply because of pipelines being taken out of service or by reduction in throughput. Some types of repairs will also require lines to be taken out of service. To illustrate, we have included a map (see sketch 1) of Northern Natural Gas Company's gas transmission pipeline, which supplies gas to the states of Iowa, Minnesota, Wisconsin, and Michigan. If an upstream segment of this gas transmission pipeline were put out of service temporarily for the test or repair, many communities located at the end of branch lines, which have sole source feed (i.e., have no other tie-in's from an alternative source), would be affected by the restricted gas supply. Therefore, in developing the time frames for the baseline assessment and continual reassessment intervals (or for allowing a variance), and the schedule for repairs, we will need to consider, among other factors, the actual adverse impact on the public of a restricted gas supply.

Pacific Gas and Electric Company Supports

More Information Needed on Gas Integrity Management Program

We have summarized the areas where OPS is seeking further information in developing a proposed integrity management program rule for gas operators. The information needs are organized under nine categories, seven of which are the elements we see as essential to any integrity management program rule. We have added two other categories to identify areas where we need information to evaluate the effect of an integrity management rulemaking on costs and gas supply, both seasonally and regionally.
To help promote discussion of these issues, we have also developed an electronic discussion forum on OPS's Internet home page. The Internet address for this forum is http://ops.dot.gov/forum. Because of the way we have interspersed numerous questions throughout this document with extensive background and technical information, some commenters may find it difficult to find the areas they would like to comment on. The electronic forum will list all the areas where we have asked for comment so that commenters can easily focus on those areas of interest to them. The electronic forum will allow real-time electronic discussion for 45 days. We hope it will increase the breadth of participation in the commenting process. A transcript of the electronic discussion forum will be placed in the docket.

1. Define the areas of potentially high consequence
Because the environmental consequences of a gas pipeline accident tend to be localized, OPS's approach to defining areas of potentially high consequences has focused on populated areas, particularly, areas of high population and areas where groups of people reside who may have difficulty evacuating an area.

Presently gas pipeline regulations are structured to provide increasing levels of protection, consistent with predetermined thresholds, where resident population is greater. Accordingly, operators of gas pipelines are required to monitor the number of dwellings within 660 feet of the pipeline, and either to lower operating pressure or to replace the pipe with one having greater wall thickness or strength as the number of dwellings increases above predefined thresholds.
The consequences of these requirements are that –

- gas pipeline operators have excellent data on populations near their pipelines, and
- pipelines operating in areas of higher population density (called Class 3 & 4) typically have thicker or stronger walls than those in lower population areas (called Class 1 & 2).

These factors, among others, differentiate gas pipelines from those that carry hazardous liquids.
Pacific Gas and Electric Company concurs that gas pipeline operators have excellent data concerning the relative population density near their pipelines, however when a class location reaches Class 3, the upper structure density threshold is reached and increased growth is not noted unless it is a building with 4 or more stories.

In the technical sessions at the Public Meeting, INGAA and AGA presented a model that related gas pipeline diameter and operating pressure to the physical boundaries of the area impacted by the heat from a gas pipeline rupture and subsequent fire (i.e., the heat affected zone). C-FER, a research and consulting organization from Canada, developed the model. C-FER validated this model by comparing the predicted heat affected zones with those actually observed in several historic gas pipeline accidents.
The model predicted that the extent of the heat affected zone for pipelines of up to 36 inches diameter and operating at pressures up to 1000 psi would be less than 660 feet. Rupture of larger pipelines that are operating at a higher pressure would lead to a larger heat affected zone. To develop both the 660-foot and the 1000-foot limits, C-FER used a mathematical model of a burning jet of natural gas emitted from a ruptured pipeline. Using the results of the model, INGAA and AGA suggested High Consequence Areas be defined as -

- all Class 3 & 4 locations as presently defined in the pipeline safety regulations;
- all locations where within 660 feet of the pipeline there are facilities housing people with impaired mobility (e.g., schools, day care centers, assisted living facilities, prisons, and hospitals);
- all locations where within 1000 feet of a pipeline that operates at pressures exceeding 1000 psi and has diameter greater than 30 inches there are facilities housing people with impaired mobility.

Pacific Gas and Electric Company concurs, if the C-FER model can be used to determine the extent of the pipeline requiring integrity assessment. The implementation of the C-FER model may reveal that an HCA does not have structures of concern within the heat-affected zone, and would not require an integrity assessment.

Critical heat flux

The INGAA/AGA analysis (developed by C-FER) used 5000 btu/hr-ft^2 as the critical heat flux for defining the impact radius. However, National Fire Protection Association (NFPA) Standard 59A and 49 CFR Part 193 both use 4000 btu/hr-ft2 as the critical heat flux value. OPS recognizes that the critical heat flux is only one element in the equation that relates pipe diameter and maximum operating pressure to the extent of the heat affected zone, and that C-FER validated this equation by comparing the predicted heat affected zones with those actually observed in several past gas pipeline incidents. However, additional information would be useful on

- the source of the critical heat flux used in the analysis.

- other standards in which the 5000 btu/hr-ft2 value is used, as well as standards in which the 4000 btu/hr-ft2 is used.
- the size of the heat affected zone in the vicinity of a ruptured hydrogen pipeline.

Pacific Gas and Electric Company supports the use of the C-FER model in the regulation. However, Pacific Gas and Electric Company would like to ensure more rigorous models can be utilized to further refine the impact. The model's benefit for limiting the size of the affected area to a reasonable zone far outweighs the added effort of determining if key structures lie between the historical 660' buffer and the extent of the C-FER calculation.

Housing

INGAA advocated that a high consequence area be limited to areas within an impact zone (discussed above) where there are more than 25 houses or a facility housing people with impaired mobility. OPS would like comment on whether an impact zone should be so limited, and if so, whether 25 houses is a reasonable number.

Pacific Gas and Electric Company believes that the C-FER model impact zone is conservative because of its guillotine line break assumption. Therefore, the limitation of the HCA analysis to the impact zone is reasonable and conservative. Using a specified number of houses or types of facilities to ascertain if the area is an HCA is also reasonable and in keeping with class location considerations within the existing code.

Other considerations

OPS is seeking information to evaluate the reasonableness of including or excluding in a definition of high consequence areas -

- all populous areas where the impact radius of a pipeline rupture would be predicted to exceed 660 feet.

  Pacific Gas and Electric Company supports integrity assessments for all pipeline segments operating within a Cl 3 or 4 whose impact radius is predicted to exceed 660 feet.

- high traffic roadways, railways, and places where people are known to congregate (churches, beaches, recreational facilities, museums, zoos, camping grounds, etc.). For example, the recent gas pipeline rupture near Carlsbad, New Mexico occurred in an unpopulated area. Twelve people died in that incident.

- areas of environmental significance. Although environmental consequences of a gas pipeline incident may be localized, we recognize, nonetheless, that a gas release can ignite and cause damage to wildlife species (animal and plants), and their habitat in the area. We seek information to determine what, if any, environmental considerations need to be addressed. Also of importance is whether these areas can be readily identified so that they can be mapped - similar to how OPS is mapping unusually sensitive environmental areas for the liquid pipeline high consequence areas.

Pacific Gas and Electric Company does not believe historical incidents warrant the need to include environmental concerns. Unlike liquid pipelines, the environmental damage is minimal and localized.

Mapping

OPS is creating the National Pipeline Mapping System (NPMS), a database that contains the locations and selected attributes of natural gas transmission lines and hazardous liquid trunk lines and liquefied natural gas facilities operating in the United States. Submission of this information has been voluntary. At present,

OPS has been provided data on pipe locations for 82% of liquid pipelines but only 40% of gas pipelines. OPS has also been mapping for hazardous liquid operators the high consequence areas defined in the liquid integrity management rule. These areas include populated areas, unusually sensitive environmental areas, and commercially navigable waterways.
These maps are useful to pipeline operators and for community and state needs. OPS is committed to continuing to provide this information. OPS intends to map the high consequence areas that it defines in a gas integrity management rule, similar to how it is mapping these areas for the liquid operators. OPS expects operators to provide their pipeline data on both high consequences areas and non-high consequence areas. This information could be in digitized form or in hard copy. OPS would expect gas operators to submit the high consequence area data as an attribute associated with the pipeline geospatial features. For operators not supplying the population data, OPS is considering using the census data that it used to map the population component of the high consequence areas for the liquid integrity rule. If an operator relies on this census-based data, the operator should be required to supplement the census data with other pertinent data in identifying gas high consequence areas. Operators would submit all data according to the NPMS standards. OPS seeks input on the impact of this strategy. OPS would also like comment on whether local distribution companies (LDCs) would prefer to use this census-based population data to define their high consequence areas.

Pacific Gas and Electric Company will not be impacted by having to submit the high consequence area information. For many of our locations, Pacific Gas and Electric Company would choose to use census-based population data when defining if an HCA has the population density to require an integrity assessment.

2. Identify and evaluate the threats to pipeline integrity in each area of potentially high consequences.

One of the key concepts advanced at the Public Meeting was the need to select the right assessment tool for each significant threat. In the INGAA presentation, threats were divided into three categories: time dependent (e.g., internal and external corrosion), static or resident (e.g., cracking introduced during fabrication of the pipe or construction of the pipeline), and random (e.g., third party damage or outside force damage). INGAA further maintained that each category of threat has technologies (or practices) useful for managing the associated risk. For example, time dependent threats would require periodic inspection and static threats would require hydrostatic testing at some time during the life of the pipeline (assuming that no significant cyclic stress -such as strong pressure fluctuations - was present). For random threats, such as third party damage and outside force, INGAA said that the right tool would involve use of risk management technologies (or practices) to prevent damage or to immediately identify the potential for damage, rather than to look for evidence of past damage. Preventive technologies or practices might include third party damage prevention and monitoring of ground movement. INGAA argued that preventive technologies and practices are needed for these random threats because the likelihood of immediate rupture when the event occurs dominates the risk.

Before an appropriate technology can be selected to assess each significant threat, a determination or definition of what constitutes a significant threat has to be made. OPS would like comment on what best defines a threat as significant.

Pacific Gas and Electric Company supports the threat definitions and inspection methods being developed under the Integrity Mgmt appendix to B31.8.

Corrosion
The most prevalent time-dependent threat is corrosion. Several technologies exist or are in development both to prevent corrosion and to identify the potential for damage from corrosion. OPS is seeking information on the factors or combinations of factors that provide the clearest indication that corrosion is a significant risk to pipeline integrity.

Pacific Gas and Electric Company supports the corrosion threat analysis, proposed inspection tools and inspection intervals being developed under the Integrity Mgmt appendix to B31.8.

Third Party Damage

The most significant threat in areas of high population is third party damage. The vast majority (over 90%) of ruptures caused by third party damage occur when the threat occurs (i.e., when the excavator hits the pipeline). However, a small fraction of third party damage failures do occur well after the impact. Therefore, technologies that look for evidence of past damage after the threat has occurred should be focused in areas where delayed failure is most likely.

OPS is seeking further information on the combination of material properties and/or operating conditions that could increase the susceptibility of pipelines to delayed failure following third party damage. For example, thick walled, high toughness pipe can sustain a strike from a third party with a much lower likelihood of immediate rupture than other pipe. In combination with some source of cyclic fatigue, such pipe can be much more susceptible to delayed rupture from third party damage. Pipelines with these characteristics in areas where the likelihood of third party damage is high need to be assessed for residual damage. OPS also is seeking information on pipeline industry efforts to explore new technologies capable of recognizing or preventing third party damage and to incorporate proven technologies into company integrity management plans.

Pacific Gas and Electric Company believes that prevention is the best mitigation for third party damage. This includes active participation in One-call and stand-by during excavation around high-risk facilities. For detection of 3rd Party damage, Pacific Gas and Electric Company has found direct assessment to be a very effective tool.

Special Conditions

The presence of one or more critical risk factors often indicates a significantly increased likelihood of other failure modes or threats. For example, pre-1970 ERW piping is known for seam cracking and subsequent rupture. Such seam cracking is difficult to detect using standard pigging technologies. In addition, thick walled, high toughness pipe can sustain a strike from a third party with a much lower likelihood of immediate rupture than other pipe. In combination with some source of cyclic fatigue, such pipe can be much more susceptible to delayed rupture from third party damage. Further, some pipelines operating at elevated temperature in a potentially corrosive environment may be especially susceptible to stress corrosion cracking. OPS is seeking information on any special characteristics that can influence pipeline risk and mode of failure. The presence of these special characteristics may necessitate the use of specially designed assessment technologies.

Pacific Gas and Electric Company believes the threat analyses developed for B31.8's Integrity Mgmt appendix adequately addresses special conditions and the risk analyses will prioritize these pipelines as one of the first to be inspected.

Erosion

Some commenters have pointed out soil erosion as a potential threat to pipeline integrity. OPS is seeking information on the conditions under which soil erosion has been a significant failure mode, including the possibility of erosion exposing the pipeline to external damage from passing water-born debris, and on the practices useful to prevent failure resulting from soil erosion.

Pacific Gas and Electric Company concurs with the Outside Force threat analysis specified by B31.8's Integrity Mgmt appendix. The presence of an erosion threat will require inspections after major storms that could create flows that expose pipelines. Pacific Gas and Electric Company's current practice is to perform an annual erosion survey, prioritize the erosion sites and mitigate the locations that could impact the integrity of a pipeline. Pacific Gas and Electric Company's contractor, performs the erosion mitigation by installing mats or palisades systems to halt and reverse the erosion.

Treatment of Storage Fields

Storage fields have been the source of pipeline integrity problems for decades. OPS is seeking information to help identify the cause of and prevent piping-related failures associated with storage fields that could affect high consequence areas.
OPS is also interested in information on the gas pipeline industry's efforts to reinvigorate the National Association of Corrosion Engineers' (NACE) standard setting or develop guidance focused on gas storage fields.

Low Stress Pipelines
The American Gas Association (AGA) and American Public Gas Association (APGA) maintain that
- pipelines operating at a stress level below 20% specified minimum yield strength (SMYS) are of low enough risk that they should not be covered by a gas integrity management program rule, and
- for pipelines operating between 20% and 30% SMYS, integrity management practices other than internal assessment, hydrostatic testing and direct assessment are adequate. (Direct assessment is a term coined by the gas pipeline industry. The term is described in detail below).

OPS is seeking the following information to determine how best to treat low stress pipelines in an integrity management rule.
- actual data on the leak and rupture history (presented by failure mode) of natural gas pipe operating below 20% SMYS and between 20% and 30% SMYS.

Pacific Gas and Electric Company concurs with the Leak vs Rupture report complete by Battelle for GTI and believes that additional leak mitigation activities could be performed instead of inspections. For the lower stress pipelines the primary concern is leak migration, so the mitigation should be focused on increased leak detection efforts instead of pipeline inspections.
- comparisons of this leak and rupture history information with the corresponding information for higher stress piping (by failure mode).
- a more thorough discussion of the process that AGA is advocating for companies operating low stress pipelines to follow to provide added assurance of integrity. Questions to be addressed include -
- Are risk profiles to be developed and maintained for low stress pipe segments that could affect high consequence areas?
- How would such risk profiles be used to support decisions on which segments require application of more extensive assessment technologies?
- What actions would be taken in response to findings?
- What means should be used to evaluate the potential consequences associated with pipe segments that fail by leaking? (e.g., Where does the potential for accumulation of leaked gas increase the likelihood of an explosion ultimately occurring as a result of an undetected leak?)
- What would be appropriate baseline and reassessment intervals for low stress lines (for those operating below 20% SMYS and those operating between 20-30% SMYS)?

Select Appropriate Assessment Technologies

INGAA maintains that gas pipeline integrity can be effectively assessed using one or more of three approaches: in-line inspection, hydrostatic testing and the direct assessment process. (The direct assessment process is discussed below). INGAA further maintains that selecting an assessment technology should be based on an analysis of all relevant risk factors to determine which threats represent the most significant risks.
Pacific Gas and Electric Company concurs with INGAA’s assertions.

Correspondence Between Threats and Assessment Technologies

To ensure that integrity management programs are designed to address the full spectrum of failure causes (threats), OPS is seeking information on the correspondence between assessment technologies and the threats they are designed to detect. Available information on the range of effectiveness of each technology would also be beneficial.

Pacific Gas and Electric Company concurs with tool-threat specification in B31.8's Integrity Mgmt appendix.

Experience with In-Line Inspection

OPS is seeking information on experience with using in-line inspection (ILI) technology. Relevant information would include the number, type and severity of features or defects discovered as a function of the technology employed, risk factors that were present, and when and how the defects were acted on. These data could help us in determining the potential number of incidents prevented through the use of ILI technology. We are also seeking data on estimated costs associated with implementing ILI technology.

Pacific Gas and Electric Company has little experience with ILI. Due to frequent diameter changes within each pipeline and the use of plug valves, extensive valve and pipe modifications are required before an ILI tool can be used. In the last two years, Pacific Gas and Electric Company has spent over $5,000,000 making 200 miles of high-risk pipelines piggable. The data from these runs are pending.

Effectiveness of Pressure Testing

INGAA contends that a pressure test conducted at any time during the life of a pipeline provides adequate assurance that so-called static or resident defects (e.g., cracking introduced during fabrication or construction) are no longer an integrity concern. The premise behind this position is that gas pipelines do not typically operate under cyclic pressure loading of sufficient magnitude to promote crack growth. Therefore, a hydrostatic or pressure test conducted at any time during the life of the pipeline will forever eliminate any concern about the risk from static or resident defects. INGAA has not claimed that a once-in-a-lifetime pressure test will eliminate concern for other types of threats such as time-dependent (e.g., corrosion) or random (e.g., third party damage). OPS is seeking information on conditions (other than changes in cyclic pressure loading) in which the premise that a once-in-a-lifetime pressure test will eliminate the risk from static or resident defects does not apply.

Incentives to Increase the Piggability of Lines

OPS is interested in promoting the appropriate expanded use of in-line inspection (or pigging) technologies. Therefore, OPS is seeking information on the current and near-term expected mileage of gas transmission lines that can be pigged, as well as on financial (or feasibility) barriers to making other lines piggable.

Direct Assessment
Direct assessment is a structured process for assessing pipeline integrity. While OPS focus on direct assessment at this stage is on assessing external corrosion, work is in process to explore its application to internal corrosion and stress corrosion cracking. The process has four basic steps:
1. A comprehensive integrative analysis of risk factor data is used to determine whether direct assessment will apply, what threats are likely to be significant, where these significant threats are likely to be present, and what tools are best suited to characterize pipe condition. Candidate data for integration include:

- Pipe characteristics (e.g., wall thickness, coating material and condition,
- pipe toughness, pipe strength, pipe fabrication technique, pipe elevation profile);
- Internal and external environmental factors (e.g., soil moisture content and acidity, gas operating temperature and moisture content);
- Operating and leak history (e.g., pipe failure history, past upset conditions that have introduced moisture into the gas);
- Land use (e.g., active farming, commercial construction, residential construction);

- Protection history (e.g., cathodic protection system and history, history of third party hits and near misses, effectiveness of local One Call systems);
- The degree of certainty about the current condition of the pipeline (e.g., age of the pipe, completeness of integrity-related records, available inspection data).

2. An above ground examination is made of the pipeline using one or more direct assessment tools to identify areas where coating defects (holidays and disbondment) are likely to exist and whether or not active corrosion is likely to be present.

3. Excavation (digging bell holes) is used to expose the pipe in areas suspected to be experiencing active corrosion, then the pipeline is examined visually, and other evaluative techniques such as ultrasonic testing are used.

4. Information from all available excavations is integrated and generalized to determine whether and where additional bell holes should be dug to seek out additional potential active corrosion**.**

Validation Process and Research & Development Efforts on Direct Assessment

The individual technologies employed in direct assessment have been utilized for pipeline integrity assessment for many years. However, the use of these technologies in an integrated process that includes analysis of risk factor data is new. Also, some new tools such as Direct (or Alternate) Current Voltage Gradient (DCVG or ACVG), Pipeline Current Mapper, C-Scan and C-Spin are being introduced. Therefore, the industry has undertaken a validation process designed to determine both the conditions under which direct assessment is most effective and the effectiveness of the overall process. OPS is providing funding for this project along with extensive project oversight. Process effectiveness will be evaluated by comparing the results from direct assessment technologies with the results from bell hole examinations and with the results from in-line inspection of the same segments. Between 15-25 pipeline operators are participating in this validation study by contributing existing assessment data and developing new data from application of the technologies. State agencies are involved in reviewing the data. OPS is seeking the following information on the direct assessment process:

- how direct assessment can be validated and applied for external and internal corrosion, including applications for dry and wet gas lines;
- the need where there are multiple threats on the same segment of pipeline for complementary supporting assessment techniques, or for additional corrective and mitigative actions, to address the multiple threats;
- whether there are conditions where direct assessment may not be possible or may not give accurate information;
- the statistical basis for validating the external and internal corrosion direct assessment process as well as the justification for this basis;
- how direct assessment can be applied and evaluated for stress corrosion cracking;
- available standards to support the use of all types of direct assessment that are envisioned;
- the most important risk factors that should be considered in analyzing the applicability of each direct assessment technology to each threat.
- the process for information integration as it relates to direct assessment.
- the application of direct assessment to uncoated pipeline.

Pacific Gas and Electric Company supports the DA standards currently being developed by NACE. In addition, our experience with DA has shown it to be an effective tool for finding the poorest sections of pipe in a segment.

Local distribution companies
AGA and APGA contend that because local distribution company (LDC) transmission pipelines are typically so closely coupled to the distribution system, hydrostatic testing would result in significant service interruptions, and pigging would be highly uneconomical if even possible. In a white paper released since the public meeting, AGA and APGA have described what alternative technologies are available, and

why alternatives provide adequate protection for these lines. (This paper can be found on the OPS web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operator Rule and in the DOT docket.)

4. Determine time frames to conduct a baseline integrity assessment and to complete repairs following an assessment using a graded (tiered) approach that prioritizes pipeline segments based on risk. A time frame will have to be determined for operators to conduct a baseline assessment of their pipe segments using a graded or tiered approach. Under this approach, an operator would prioritize all applicable pipeline segments for assessment based on the risk the segments pose to the high consequence areas. The risk would be determined from risk factors. A schedule for completing repairs of the segments after the assessment would also be based on risk factors. One of the factors in developing the required time frame, or establishing variances from the required time frame, would be the need to maintain gas supply to the public.

Pacific Gas and Electric Company concurs with the time frame and risk-based prioritization proposed by B31.8's Integrity Mgmt appendix.

Baseline Assessment

The INGAA presentation did not discuss a time frame for a baseline assessment. To help develop a required baseline assessment schedule that considers the various risk levels for each pipe segment to be assessed, OPS is seeking the following information.

- practical considerations of establishing a graded (or tiered) approach for conducting a baseline assessment. A graded approach is one where baseline assessments of the highest risk pipeline segments are conducted as soon as possible with baseline assessments for lower risk segments completed subsequently. Risk would be determined from risk factors, whether specified, operator-developed or a combination.
- the time required for the industry to mobilize (e.g., develop models and perform needed risk analysis, complete demonstration of needed technologies, train and qualify the resource base needed to support a baseline assessment).
- information on the impacts to the gas supply and to the cost of gas if a time frame for completing a baseline assessment were required, for example, a time frame of 5, 10 or 15 years
- repair criteria currently being considered. Criteria would include time frames for competing repairs following an assessment.

5. Identify and Implement Additional Preventive and Mitigative Measures

INGAA submitted a report (prepared by the Hartford Steam Boiler Inspection and Insurance Company) that summarizes the range of threats identified as causing failure in gas pipelines, the management practices industry is using to manage these threats, and the research contributing to the understanding of the threats. (This report is available in the DOT docket and on the OPS web site under Initiatives/Pipeline Integrity Management Program/Gas Transmission Operator Rule.)

- OPS is seeking unattributed examples of typical decision processes that an operator uses to manage threats to pipeline safety by implementing discretionary preventive or mitigative technologies or practices such as those discussed in the Hartford Steam Boiler report.

As part of the integrity management process, an operator would need to take additional measures to prevent and mitigate the consequences of a pipeline failure in high consequence areas. In the liquid integrity management rule, operators are required to conduct a risk analysis of each pipeline segment to identify additional measures to enhance safety and environmental protection. For gas pipelines, additional preventive and mitigative measures could include actions such as damage prevention best practices, better monitoring of cathodic protection, establishing shorter inspection intervals, and installing Remote Control Valves (RCVs) and Automatic Shutdown Valves (ASVs) on pipeline segments.

- OPS is seeking information on the effectiveness, technical feasibility, economic feasibility, and reduction of risk with RCVs and ASVs.

Pacific Gas and Electric Company's example of using risk management to manage threats is as follows:
On an annual basis, we develop our budget which includes ~$20 million of threat mitigation activities that are not required by current codes. Three groups propose the projects that comprise this budget...operations, engineering and risk management.

During the budget period (April-August) risk evaluations (based on continually updated data in GIS) are completed for each project proposed by operations and engineering. Concurrently, the risk management group reviews the risk evaluations for every mile of transmission pipe and proposes inspection or mitigation projects. The Total risk value determined in these evaluations is used to prioritize the projects and determine the projects that will be funded.

When prioritizing future projects, Pacific Gas and Electric Company also considers the B/C and the individual likelihood for each threat. Projects with a high B/C (large risk reduction vs. cost) or high likelihood of failure due to a specific threat are raised in priority...even if the total risk value is low.

During the rest of the year, the risk management team receives feedback about threats from several sources;
1) Inspection reports when pipelines are exposed,
2) Pipeline Risk Evaluation forms...a intra-net form that can be filled out by any crew member that notes a threat to the pipeline. The form is sent to the risk mgmt team which must respond with an analysis of the threat level and proposed response,
3) An annual review of known and new erosion concerns
4) Pipeline patrol reports

The input of each of these sources is evaluated and incorporated into GIS (for future risk calculations). If the threat is large, funding is immediately secured for inspections or mediation.

6. A Process for Continual Evaluation and Assessment to Maintain a Pipeline's Integrity.
Integrity assurance involves periodic assessment of the integrity of each pipeline segment within a high consequence area, periodic evaluation of the entire pipeline to determine threats relevant to the pipeline segment, and repair of problems.

Periodic Reassessment
Times frames need to be developed for an operator to periodically assess the integrity of its pipeline segments. At the public meeting, INGAA recommended a periodic reassessment interval for all technologies (i.e., in-line inspection, direct assessment and hydrostatic testing) of 10 years for pipe of thickness typically used in Class 1 & 2 locations, and 15 years for pipe of thickness typically used in Class 3 & 4 locations. INGAA said these reassessment intervals were conservative estimates of the maximum time between pipeline inspections to prevent failure of the largest defect and that they were developed based on very conservative assumptions on corrosion growth rate that were checked against both analysis and experience data. INGAA further explained that these reassessment intervals assumed that at the beginning of the interval, the pipe thickness was not less than that of new pipe appropriate for the class location. Thus, there would be variations in the actual reassessment interval depending on the assessment technology. INGAA noted that an operator might be able to extend the reassessment interval based on its knowledge of and demonstrated control over the principal risk factors for its pipeline, but that if any of the data on key risk factors were missing, then an operator would need to develop a shorter reassessment interval.

OPS is seeking information to help it detemine appropriate periodic reassessment intervals. This information could include examples detailing a proposed reassessment interval following a successful baseline assessment and repair of problems found during the assessment. These examples could use the INGAA proposed intervals or any other, such as those required in the liquid pipeline integrity management rules. The examples could also factor in repair criteria used to re-mediate problems found during the baseline assessment.

Pacific Gas and Electric Company supports the assessment intervals specified by B31.8's Integrity Mgmt appendix unless a robust risk management assessment can justify longer intervals.

In some cases pipelines have been designed for placement in Class 3 and 4 locations by using steel with greater toughness and strength rather using pipe having greater wall thickness. These pipelines are no less susceptible to corrosion damage; therefore, OPS is considering whether a reassessment interval should be defined by the wall thickness rather than by the Class location for a pipeline segment. OPS would also like information on how a reassessment interval would factor in the impact of increased ligament strength where higher strength pipe is used rather than thicker pipe.

Repairs
Following the reassessment, an operator would have to schedule repairs on the pipeline segments. This would be done by prioritizing the anomalies found during the assessment for evaluation and repair. The schedule, which would be risk-based, would need to provide time frames for evaluating and completing repairs. In the liquid integrity management rule, we provided time frames for an operator to complete repair of certain conditions on a pipeline following an assessment. For those conditions not specified, we allowed the operator to provide time frames for evaluating and completing the repairs. The schedule was to be based on specified and pipeline-specific risk factors.

Pacific Gas and Electric Company supports the repair schedule specified by B31.8's Integrity Mgmt appendix

Comment is sought on the time frames to complete needed repairs and factors that need to be considered in establishing these time frames. One factor could be the impact on the gas supply. If no other guidance is available on scheduling repairs, OPS may develop a repair schedule similar to that used in the liquid integrity management rule.

Evaluation
A periodic evaluation looks at all available information about the entire pipeline to determine what could be relevant to the pipeline segment being examined. The frequency at which evaluations are conducted could be based on risk factors, either specified factors, operator-developed or a combination. We seek comment on how to determine frequency and how to ensure that information is analyzed on all threats to a segment.

Direct Assessment
OPS is seeking information on the logistics of rapidly expanded use of Direct Assessment technologies, particularly on whether the current pool of trained and qualified assessors would pose any constraint to industry's ability to rapidly expand the use of these technologies. This issue should also be considered in conjunction with any input on the best strategy for establishing a baseline assessment interval.

7. Monitor the Effectiveness of Pipeline Integrity Management Efforts
OPS is seeking information on how it could best monitor the effectiveness of operator integrity management efforts. Information is needed both on specific direct performance measures and on indirect measures derived from analysis of assessment results and corrective actions taken. OPS and the industry have been criticized for an ineffective system that assembles incident data, analyses it for possible implications to other pipelines, communicates across the industry the general lessons and implications of the these incidents, and follows up to evaluate the effectiveness of operator incorporation of the general lessons from these incidents. Some work to address this issue is ongoing, such as revised reporting criteria. OPS is seeking input on potential additional actions that could be taken jointly by OPS and the industry to address this concern.

Pacific Gas and Electric Company supports program effectiveness metrics specified by B31.8's Integrity Mgmt appendix

8. Consideration of Impact on Gas Supply
OPS needs information to evaluate the effect of new safety requirements on gas supply to residents. This is one of many factors that OPS will need to consider in establishing a baseline assessment time frame. Information is needed on how gas supply would be affected with baseline assessment time frames of 5, 10 and 15 years. The same information is needed for reassessment intervals of 5, 10, 15 and 20 years.

9. Other Issues Including Those Related to Cost/Benefit
Scope of Integrity Management Planning
Earlier in this document OPS explained its current thinking about the scope of a proposed integrity management rule. OPS would like comment about its underlying assumptions.

Cost Benefit Analysis
To support its cost benefit analysis, OPS is seeking additional information on the following topics:

- Benefits and costs of a company's active-in-line inspection and pressure testing programs. Information could include the results on safety such as the reduction of accidents or leaks.

Pacific Gas and Electric Company has none available at this time. In-line inspection and pressure testing for integrity assessment has been limited and is just beginning to be used.

- Benefits and costs of a company's integrity assessment program employing direct assessment technologies. Information could include the types of direct assessment that have been used or considered. The costs associated with the technologies. The results related to safety, such as the reduction of accidents or leaks reduced.
- The total mileage of gas transmission pipeline. The number of miles of gas transmission pipelines that have been hydrostatically tested to current standards. The number of miles of gas transmission pipelines that have been pigged at least once.

Mi. Pipe	**Mi. w/hydro**	**Mi. pigged**
6,300	**3,900**	**200**

- The estimated average cost per mile to hydrostatically test a gas transmission pipeline. The fraction of this cost that is associated with taking the line out of service. Ways to minimize the cost associated with taking the line out of service, such as using existing looping.

<=12”	**20”**	**30”**	**40”**
$100,000	**$300,000**	**$400,000**	**$500,000**

The cost is predominantly due to two factors…1) Preparation of the pipeline for hydrotesting and 2) disposal of the hydrotest water. California’s environmental regulations necessitate storing the water in Baker tanks prior to disposal.

- The estimated average cost per mile to internally inspect a gas transmission pipeline. The fraction of this cost that is associated with taking the line out of service. Ways to minimize the cost associated with taking the line out of service, such as using existing looping.

<=12”	**24”**	**34”**
$800,000	**$1,200,000**	**$2,000,000**

Pacific Gas and Electric Company derived these estimates from the actual costs for the first three ILI projects we have initiated. The cost of taking the line out of service was negligible. The majority of the cost was due to making the pipeline piggable and accessible for a pig launcher and receiver. Roughly the costs segregated as follows….10% contract cost for running the ILI, 10% Pacific Gas and Electric Company labor cost to prepare for and monitor the pig run, 80% for replacing valves, installing scraper bars and setting up for the launcher and receiver. We anticipate that Pacific Gas and Electric Company’s labor cost will reduce by 50% as we become more familiar with ILI.

- The percentage of an operator's pipelines that are not capable of being pigged. The reasons the pipeline is not piggable, for example, because it is telescopic, has sharp radius bends, or has less than full opening valves The costs to make the line piggable.
  Over 80% of Pacific Gas and Electric Company's pipelines are not piggable because they have one or more of the following…telescopic construction, random diameter construction, sharp radius bends, and less than full opening valves. In addition, all lines require the expense of building piping that will enable the launching and receiving of an ILI tool. The costs sustained to date are described in the previous question.
- Impacts on small businesses. The impacts an integrity management rulemaking will have on the company. Include any special concerns that RSPA should consider in addressing impacts on small businesses. Include whether there are alternative requirements for small businesses that are less onerous.
- The estimated average cost per mile to use direct assessment on a gas transmission pipeline. The assumptions this estimate includes on the number of bell holes required per mile.
  Pacific Gas and Electric Company has been effectively using direct assessment for many years. The average cost for a direct assessment survey is $1,100/mile and $30,000/bellhole.
- The estimated average cost per mile to change out a gas transmission pipeline to comply with existing class location regulations. The number of miles per year that are typically replaced to comply with this regulation.
- The best available data on the actual costs associated with reported gas pipeline incidents.
- An inventory of pipeline mileage for pipe having diameter greater than or equal to 30 inches and MAOP greater than or equal to 1000 psi.
  Pacific Gas and Electric Company has 182.3 miles of pipeline with OD >= to 30" and operating over 1000 psig. The mileage by Class location is…Class 1 - 176.6 miles, Class 2 - 5.2 miles, Class 3 - 0.5 miles

Standards

During the public meeting, INGAA stated that consensus standards represent a practical way to institutionalize both the uses of new technology and the effective application of existing technology. INGAA said that standards currently being developed should provide detailed information for operators in implementing any integrity management rule that is eventually issued.

OPS is seeking information on the schedule the Standards Organizations have for completing the various standards that relate to integrity management that are expected to be prepared, particularly the standards on conducting integrity assessments and repair criteria. The current "draft" Schedule on Standards is found at the end of this Notice.

Industry Data Analysis

We believe that data sources outside OPS incident data should be considered in developing risk analysis and assessment intervals. OPS seeks to better understand the extent to which data beyond these incident histories, including data from all incidents and near misses, were used to validate industry positions.

NTSB PGE Comments Valves

PHMSA-RSPA-1997-2879-0004

Pacific Gas and Electric Company

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Donald W. Anderson
Manager
Gas System Technical Support

November 20, 1997

PG&E

United States Department of Transportation
Office of Pipeline Safety
Research and Special Program Administration
Dockets Facility, Plaza 401
400 Seventh Street, SW
Washington, DC 20591-0001

Subject: Docket No. RSPA-97-2879 -4
Remotely Controlled Valves on Natural Gas Facilities

Ladies and Gentlemen:

Pacific Gas and Electric Company (PG&E) is a public utility serving over three million gas customers in Northern and Central California.

Thank you for the opportunity to comment on your survey on the use of remotely controlled valves (RCVs) on natural gas facilities. Attached are written comments that address the eight issues identified in the Docket.

Sincerely,

[redacted]

RTA:as

Attachment

3 pgs

Pacific Gas & Electric's Comments to the Survey on the Use of Remotely Controlled Valves (RCVs) on Natural Gas Pipeline Facilities

DOT 49 CFR Part 192 [Docket No. RSPA-97-2879; Notice 1]

General Comments:

Pacific Gas & Electric has no objections to installing RCVs on natural gas facilities. In most cases, RCVs are installed when we upgrade an existing major control station or build a new one. We have historically installed SCADA and controls necessary to remotely position the regulating and routing valves at this type of facility and have experienced few problems with the remote operation of any valve.

However, Pacific Gas & Electric does agree with the findings relating to Automatic Controlled Valves (ACVs) in the GRI sponsored report entitled "Remote and Automatic Main Line Valve Technology", July 1995. In our experience, ACVs have proven unreliable because the pipeline failure detection systems used to trigger the closure of ACVs often mistake normal operating transient conditions as a pipeline failure. In order to avoid false closures due to normal transients, the detector system sensitivity must be severely reduced, in some cases, to the point of inoperability on a full line break.

The following are our comments to the specific issues identified in the Docket:

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 damaged?

Early detection and isolation will enhance safety by reducing the volume of flammable gas being vented at the pipeline break. The reduction of property damage is questionable since isolation of the pipeline section will only reduce the duration of the gas released to atmosphere. The peak gas flowrate at the pipeline break is unaffected, and it is expected that most of the property damage will occur during the first few seconds of the pipeline break.

B. What are the technical and economical advantages of installing RCVs?

A major technical advantage is the ability to isolate the pipeline break quickly without requiring personnel to be sent to operate any mainline valve(s). Also, the mainline valve status (valve position) can be monitored remotely from central gas control centers.

The economic advantages are: 1) minimizing the company's liability by reducing amount of flammable gas discharged at the pipeline break, and 2) potentially minimizing gas customer outage by quickly isolating the line break, and either providing an alternate supply of gas to the customer, or curtailing interruptible gas customers.

C. What are the technical and economical disadvantages of installing RCVs?

The main disadvantages of installing RCVs are higher installation and maintenance costs and a more complex installation. RCVs, with their associated SCADA systems, are more complex and could compromise customer reliability. The potential for an inadvertent pipeline shutdown also increases which could result in costly customer re-lights as well as negative publicity.

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

In California there are no regulations presently adopted regarding the use of RCVs on natural gas pipeline facilities.

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?

High risk areas could be based on 1) the potential magnitude of damages that could occur if a pipeline breaks, or 2) the probability of a pipeline break actually occurring. Population density, pipeline pressure, and pipe diameter are items that impact the potential magnitude of the damage. Known hazardous locations (such as, older pipelines crossing known major earthquake fault lines, or areas subject to land slides or erosion), forecast construction activity next to the pipeline, and pipeline pressures all relate to the probability of a pipeline break.

It should be noted that the current pipeline safety regulations already specify design factors based on population density (i.e., Class Locations). High population densities adjacent to natural gas pipelines require operators to install pipelines with a higher factor of safety. Furthermore, transmission valve spacing requirements are also based on population density.

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

There are no cases in our experience where an RCV malfunctioned causing it to close unexpectedly. However, there are instances when the RCVs failed to close when commanded by the dispatcher. These failures have been due to maintenance issues, loss of communications, or lack of power to the actuators.

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

We do not have any documented cases where an RCV operated after an accident. However, there have been cases where a dispatcher remotely closed an RCV due to concern that a pipeline break was eminent.

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.

It is logical to assume that if there is an ignition, it would occur within the first few seconds of a natural gas pipeline break. First, if the pipeline break was caused by a dig-in from construction or farm equipment, such as a tractor, backhoe, etc., the equipment itself would likely contain a source of ignition. Secondly, if there is a underground pipeline break, the debris adjacent to the break (dirt, rock, sand), as well as portions of the steel pipe, would be violently expelled by the high pressure gas resulting in a high probability of a spark and ignition of the flammable gas within seconds of the initial pipeline break.