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NH PUBLIC UTILITIES COMMISSION

Debra A. Howland, Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

RE: Docket No. DRM 11-077

Dear Director Howland:

Enclosed for filing in the above-referenced rulemaking proceeding, please find the Comments of Northern Utilities, Inc.

Please contact me at your convenience if you have any questions concerning this matter.

Sincerely,

Gary Epler
Attorney for Northern Utilities, Inc.

Enclosure

cc: Service List (by e-mail only)
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STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

Docket No. DRM 11-077

PUC 500 – Rules for Gas Service	)	Comments of Northern Utilities, Inc. on Proposed Rules

Northern Utilities, Inc. ("Northern" or "the Company") appreciates this opportunity to provide written comments on the Commission's proposed Chapter 500 Rules for Gas Service. Northern is New Hampshire's second largest gas local distribution company ("LDC"). The Company operates roughly 500 miles of gas main in the state and provides service to approximately 29,000 customers in 21 communities in the Seacoast Region. The Company's affiliates operate gas distribution systems in Massachusetts and Maine, as well as an 87-mile FERC-regulated natural gas transmission pipeline primarily in Maine and New Hampshire.

Northern is committed to providing gas service that is safe and reliable. The Company is proud of its gas safety record in New Hampshire, and believes that its success is attributable to its deep understanding of the system it operates, its development of internal policies and procedures to safely operate and maintain the system, and its dedication to training a qualified work force to ensure that risks on the system are appropriately identified and efficiently managed.

A. Natural Gas Safety Regulation Transitions to Integrity Management.

It is important for the Commission to recognize that since its last comprehensive gas service rulemaking, there have been important developments in how gas safety regulation is approached. Long gone are the days when a purely prescriptive regulatory framework was deemed to be most effective. Today, while prescriptive regulation still has its place in some aspects of gas regulation, the industry's vision of gas safety has evolved to recognize that each gas distribution system is unique, and the operators who work daily with their systems are best positioned to manage the risks on their systems. Instead of imposing one-size-fits-all prescriptive regulation, the regulatory landscape is shifting toward a risk-based integrity management paradigm.

In 2009, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA"), adopted new integrity management rules for pipeline operators. The rules, codified at 49 C.F.R. §192, Subpart P, are based on the recognition that the diversity existing among gas operators and their systems renders traditional prescriptive regulation impractical.[1] PHMSA's rules, dubbed the Distribution Integrity Management Program ("DIMP"), required operators to develop and implement a company-specific integrity management plan ("IMP") by August 2011.[2] The IMP is effectively an individualized company-specific comprehensive risk management program that is tailored to each unique natural gas distribution system.[3]

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[1] PHMSA's Integrity Management for Gas Distribution Report of Phase 1 Investigations concluded:

> Differences between gas distribution pipeline operators, and the pipeline systems they operate, make it impractical simply to apply the prescriptive integrity management requirements for transmission pipelines to distribution. The significant diversity among gas distribution pipeline operators also makes it impractical to establish prescriptive requirements that would be appropriate for all circumstances.

Integrity Management for Gas Distribution, Report of Phase I Investigations at 1 (Dec. 2005) (available at http://primis.phmsa.dot.gov/dimp/history.htm).

[2] For additional background on DIMP we have attached a set of FAQs issued by PHMSA on DIMP as Attachment A. Sections B and C of the FAQ, in particular, provide helpful general background.

[3] Integrity management uses a high-level, flexible program developed by the operator with the following key components:

1. Knowledge of infrastructure,

This risk-based approach was designed to promote continuous improvement in pipeline safety by requiring pipeline operators to identify and invest in risk control measures beyond core baseline regulatory requirements. The basic principle underlying integrity management is that "operators should identify and understand threats to their pipelines and apply safety resources that commensurate with the importance of each threat."[4] This risk-based approach is superior to prescriptive rulemaking because a prescriptive rule ignores the differences between gas distribution pipeline operators and the pipeline systems they operate. What may be "best" for one utility's system is likely not the "best" for all others.[5]

In addition to generally improving public safety, integrity management also deploys ratepayer dollars more efficiently. A prescriptive rulemaking approach has the potential to allocate pipeline safety resources in an ineffective or inefficient manner because dollars are spent as prescribed by regulation. Unless it can be demonstrated that all systems share a common risk, and that risk has the same priority on each system, ratepayer dollars will not be deployed most efficiently under prescriptive regulation. Under integrity management, by contrast, dollars are

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2. Identification of threats that are applicable to the specific operator and system,
3. Evaluation and ranking of risk,
4. Identification and implementation of measures to address risk,
5. Measurement of performance,
6. Monitoring results, and
7. Evaluation of program effectiveness.

[4] Fed. Reg., Vol. 74, No. 232 at 63906.

[5] During the October 19 Public Hearing, Staff noted that there are three gas LDCs operating in New Hampshire, and asserted that the differences among them are not significant. The Company respectfully disagrees. While that assumption served as the basis for prescriptive gas safety regulation for decades, DIMP acknowledges that diversity does indeed exist in the real world. To illustrate this point, the Company has provided as Attachment B, a comparison of the three New Hampshire LCDs in terms of their mains by material type and reported leaks. A casual review that attachment demonstrates that each LDC has its own unique risk profile.

allocated commensurate to each risk identified on the operator's system. Because risks are being managed in accordance with their rank, resources are being efficiently allocated to effectively manage risk. In other words, ratepayers receive the greatest improvement in public safety for their dollar under integrity management.

As a result of the evolution in gas safety regulation, a recurring theme in the Company's Comments is that the Commission's proposed Chapter 500 rules—like Section 192 Subpart P—should recognize the diversity among distribution systems in New Hampshire and avoid "one-size-fits-all" prescriptive requirements when possible. We recommend an approach that provides operators an appropriate degree of flexibility to avoid the commitment of significant safety and financial resources on prescriptive requirements that may not be commensurate with measurable or known risks to a particular system, and will therefore result in an allocation of resources that does not maximize public safety.

Finally, while these Comments emphasize the benefits of IMP, IMP is not a silver bullet. The Commission must determine the appropriate balance between prescriptive and risk-based gas safety regulation. In these Comments we provide the Commission our views, based on our knowledge of the industry and our system, of where performance-based regulation is best applied, and where prescriptive regulation will result in the inefficient spending of ratepayer dollars.[6]

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[6] During the public hearing on October 19, it seemed clear that the gas system operators favored fewer prescriptive regulations, while the propane industry favored the prescriptive approach. The gas and propane industries have more differences than they do similarities, including the fact that propane system operators are not subject to integrity management. Thus, the Commission could employ a more prescriptive approach with the propane industry if those operators are more comfortable operating under that paradigm. No provision of New Hampshire law requires the Commission to regulated gas and propane operators identically, and the differences between their operations suggests that they should not be treated the same.

We look forward to working with the Staff and Commission on this rulemaking, and hope that these Comments provide helpful guidance on the issues presented.

COMMENTS ON PROPOSED RULES

I. PUC 504.03 Pressure Requirements.

A. PUC 504.03(e) Service I.D. Tags.

PUC 504.03(e), as proposed, would require installing a new permanent identification on services with a delivery pressure greater than 13.8 inches water column (~0.5 psig).[7] The proposed rule states:

> For pressures at the outlet of any customer's service meter that exceed (b)(2) above, a permanent identification that includes the maximum delivery pressure shall be installed and maintained at the service meter.

Currently, Northern has approximately 1,700 customers that receive service at a delivery pressure greater than 13.8 inches water column. We identify those customers for our technicians in three ways: (1) for services with a delivery pressure of 2 psig that utilize fixed factor measurement,[8] each service is marked with a red sealant cap on the regulator adjustment screw; (2) for services with a delivery pressure greater than 2 psig (commercial & industrial applications) the Company uses instrumented meters that indicate delivery pressure; and (3) the Company's Customer Information System ("CIS"), which interfaces with the technician's Mobile Dispatch Work Order System and flags for the technician that the customer receives higher

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[7] Inches Water Column: a pressure unit required to support a vertical column of water one inch high. Usually reported as inches w.c. (water column) at a specified temperature; 27.707 inches of water is equal to one pound per square inch (psi).

Psig: (pound-force per square inch gauge) is a unit of pressure relative to atmospheric pressure at sea level.

[8] Fixed factor measurement is essentially a method for taking into account the additional energy contained in a volume of gas delivered under higher pressure.

pressure service. In addition, the Company requires all Service Technicians to physically check the customer's delivery pressure on all service lines when changing, installing or working on a meter.

Based on the Company's existing practice, the proposed tagging system provides no operational benefit for the Company and only a limited benefit to the customer. The Company has no knowledge of any safety incidents that have resulted from our existing practice and no indications that this issue has been identified as an area of concern during any PUC Safety Inspections. Yet the proposed new rule would require the implementation of new a program for the installation of I.D. tags and the development of a new inspection protocol that would increase the cost of service without any measurable or known improvement to public safety. The Company has prepared preliminary cost modeling and estimates that the cost to install these new tags and develop the necessary computer programming changes to our asset tracking system and inspection program to all 1,700 locations would be approximately $60,000.[9]

The proposed regulation is an example of why prescriptive regulation should be used only when necessary. Northern already has procedures in place that properly manage the risk that the proposed rule apparently intends to mitigate. The proposed rule, if adopted, would require Northern to spend approximately $60,000 of ratepayer money to "fix" something that is not broken on Northern's system. If an additional $60,000 are to be collected from ratepayers to reduce risk on Northern's distribution

[9] During the Public Hearing Staff requested that work papers be submitted to support cost estimates provided in Comments. Work papers for the Company's cost estimates are provided in Attachment C.

system, those resources would be more prudently directed toward the mitigation of risks identified on Northern's system that are higher than the risks posed by the services affected by the proposed rule.

Furthermore, to the extent this regulation is being proposed in response to issues encountered on another operator's system, it only serves to highlight the fact that diversity exists among New Hampshire operators. As such, the regulation is intended to address an issue that is not common to all distribution systems, yet imposes the requirement (and resulting costs) to all operators.

If the Commission concludes that a prescriptive rule is worth the added cost, Northern proposes that the rule state:

> *For a customer delivery pressure that exceeds 13.8 inches water column a permanent identification, which includes the maximum delivery pressure, shall be installed and maintained in close proximity to the outlet of the meter, in conjunction with established service line inspection programs.*

B. PUC 504.03(f) Written Agreements

PUC 504.03(f), as proposed, would impose a new requirement for written agreements with customers for delivery pressure greater than 13.8" water column be retained for the life of the service meter:

> All written agreements with the customer that include delivering pressure greater than 13.8 inches of water column shall be retained for the service life of the service meter.

The Company does not understand the intent of this provision. Plainly read, it requires that any written agreements with certain customers be retained "for the service life" of the meter. The rule appears to assume that there is a relationship between the duration of a customer contract and the service life of a meter. In fact, there is no such relationship. Service meters get changed for a variety of reasons (*e.g.*, third-party damage,

age, obsolescence) that have nothing to do with the contract between the Company and the customer.

For example, assume the Company installs a meter at a location with a delivery pressure greater than 13.8” w.c. and retains the written agreement as required. A week later, the meter is damaged by a motor vehicle accident and subsequently removed, retired and replaced with a new meter. Under the provision as written, the Company would no longer be required to retain the customer agreement because the meter was replaced.

Similarly, assume that customer ABC Inc. leases office space in a new newly constructed building and enters into a one-year contract for gas service. The gas meter installed in the new building has an expected service life of 35 years. At the end of the one-year gas contract, ABC Inc. vacates the premises and XYZ Corp. moves in and signs a one-year gas supply contract. Under the proposed rule, the Company is required to retain ABC Inc.’s contract for 34 years after the expiration of its term, based on the service life of the meter where it leased office space.

While these examples are not far-fetched, they clearly illustrate the problems associated with a regulation that ties record retention requirements to the service life of a gas meter. Because we do not understand the intent of this proposed rule, the Company cannot recommend alternative language. We suggest that this proposed rule be further explored during a technical session so the stakeholders can better understand the intent of the proposed regulation, the improvement in public safety it is expected to provide, and work together toward a reasonable solution.

II. PUC 504.05 Emergency Notification

A. PUC 504.05(a)(8) Gas Facility –Related Incident

PUC 504.05 (a)(8) is a proposed new rule for reporting gas facility related incidents:

(a) The utility shall notify the safety division of the commission by telephone when any of the following occur:

* * * *

(8) A gas facility-related incident that the utility is aware of, including any incident that is likely to be, or has been, reported in the news media; . . . .

The Company agrees that it is important to keep the safety division informed of events that may occur on the distribution system that affect public safety or system reliability. But the term "facility-related incident" is vague and can lead to multiple reasonable interpretations of when a "facility-related incident" has occurred that requires reporting.

PUC 504.05(a) has an existing subsection (7), proposed to be renumbered as subsection (10), which requires reporting of:

(10~~7~~) An event which is significant in the judgment of the utility, even though it is not describe above.

In order to make the reporting requirement more clear, yet also retain the existing provision that relies on the utility's judgment for reporting, the Company proposes to combine the newly proposed 504.05(a)(8) and the existing 504.05(a)(7) into a single provision as follows:

An event which involves natural gas escaping from facilities owned or operated by the gas utility that is significant in the judgment of the gas utility operator and/or has been or is likely to be reported in the news media (e.g., shutdown of a major highway, arterial roadway or rail system).

B. PUC 504.05(a)(9) Odorant Levels

PUC 504.05(a)(9) is a proposed new regulation that requires PUC notification for indications of insufficient odorant levels:

{W3387356.1}

(a) The utility shall notify the safety division of the commission by telephone when any of the following occur:

* * * *

> (9) Any indication of insufficient levels of odorant that do not meet the requirements of 506.02(l),[10] regardless of how the operator becomes aware of such indication; . . . .

The Company agrees that odorant is important and that insufficient odorant levels should be reported to the safety division when confirmed to exist. The Company performs odorant checks on a monthly basis, which exceeds the minimum federal code requirement. *See* 49 C.F.R. § 192.625(f).[11] Although there have apparently been reported incidents of insufficient odorant in propane delivered by rail to New Hampshire, the Company is not aware of any instances where pipeline-supplied natural gas has been found to have insufficient odorant in the State.

The Company is concerned that the phrase "[a]ny indication of insufficient levels" may lead to unnecessary false reports. For example, Northern's field personnel are trained to perform "sniff tests" when working at a customer's premises to confirm the presence of odorant. Under the proposed rule, if a technician attempted a sniff test but was unable to detect odorant due to field conditions (*e.g.*, outdoors on windy day), then that could be considered within the reporting requirement of the proposed rule.[12] We do not believe that this type of situation is intended to trigger a reporting obligation under the proposed rule, yet such a circumstance could fall within the proposed language. The Company proposes the

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[10] This citation should be to Section 506.02(m) of the proposed amended rule.

[11] Section 192.625(f) states:

> To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.

[12] If such a circumstance were presented to a technician and the technician were concerned that the gas had insufficient odorization, the Company would perform a follow-up test with instrumentation designed to detect odorant.

following language to avoid this issue:

> *(9) When the operator confirms that levels of odorant do not meet the requirements of 506.02(m).*

III. PUC 506.01 Pipeline Safety Standards.

A. PUC 506.01(d) Destructive Testing -- Welding.

PUC 506.01(d) is a newly proposed section that addresses welder qualification requirements as follows:

> Utilities shall ensure that welders performing welding work on utility pipeline facilities are qualified, as follows:
>
> 1. No utility shall permit a welder to make any pipeline weld unless the welder has qualified by destructive testing within 27 months, but at least once every 2 calendar years in accordance with 49 C.F.R. §192.7 and Appendix C to Part 192.
>
> 2. Utilities shall verify that any welder originally qualified under an earlier edition of Section 6 of American Petroleum Standard 1104, Welding of Pipelines and Related Facilities as referenced in 49 CFR §192.7, shall be certified by the referenced edition.
>
> 3. PUC 506.01(d)(1) and (2) shall not apply to those portions of LNG facilities or propane storage facilities that are not subject to 49 CFR Part 192.
>
> 4. No utility shall permit a welder to weld with a particular welding process unless the welder has engaged in welding with that process within the preceding 6 calendar months. Utilities shall verify that a welder who has not engaged in welding with that process within the preceding 6 calendar months is requalified for that process as set forth in subsections (1) and (2) above.

Welding on steel pipelines is regulated under federal law at 49 C.F.R. § 192, Subpart E. Section 192.227(a) addresses welder qualifications:

> Except as provided in paragraph (b) of this section, each welder must be qualified in accordance with section 6 of API 1104 (incorporated by reference, see § 192.7) or section IX of the ASME Boiler and Pressure Vessel Code

> (incorporated by reference, see § 192.7). However, a welder qualified under an earlier edition than listed in § 192.7 of this part may weld but may not requalify under that earlier edition.

The multiple qualification requirements under Section 6 of American Petroleum Institute's ("API") 1104 standards require specimen joints to be produced and then destructively tested for determination of welding qualification. Once a welder is qualified to weld on steel pipelines in accordance with Section 6 of API 1104, they remain qualified as long as they continue to meet the requirements of Section 192.229(c):

> A welder qualified under §192.227(a) --
> (1) May not weld on pipe to be operated at a pressure that produces a hoop stress of 20 percent or more of SMYS unless within the preceding 6 calendar months the welder has had one weld tested and found acceptable under the sections 6 or 9 of API Standard 1104 (incorporated by reference, see §192.7). Alternatively, welders may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year, but at intervals not exceeding 7½ months. A welder qualified under an earlier edition of a standard listed in §192.7 of this part may weld but may not requalify under that earlier edition; and
> (2) May not weld on pipe to be operated at a pressure that produces a hoop stress of less than 20 percent of SMYS unless the welder is tested in accordance with paragraph (c)(1) of this section or requalifies under paragraph (d)(1) or (d)(2) of this section.

Therefore, from a Federal Code perspective, a welder is qualified indefinitely to weld on pipelines after a <u>single</u> destructive test (in accordance with API 1104), and then <u>maintains on-going qualification status</u> by having welds tested with radiographic examination ("X-Ray") at least twice each calendar year at intervals not exceeding 7-½ months.

Northern believes that welding of pipelines requires industry specific training and knowledge, but also requires physical ability (*e.g.*, good eyesight, sufficient handeye coordination, etc.). Recognizing that a welder's physical condition could change and/or deteriorate over time, Northern requires all welders (contractor and in-house) to perform a Multiple Qualification (*i.e.*, a destructive test) in accordance with Section 6 of API 1104 at intervals not exceeding 60 months, which significantly exceeds the Federal code requirement of a single destructive test. This 60-month period was developed by the Northeast Gas Association ("NGA") Welding Committee, which was comprised of industry representatives and state regulators[13] who jointly provided input on and developed a NGA Welding Procedure that all operators could use, including welder requalification intervals. This procedure was developed after careful consideration by regulators and industry stakeholders and Northern believes that this 60-month period is reasonable and strikes an appropriate balance between: (1) ensuring that welders are qualified and physically capable of performing acceptable pipeline welds; and (2) the cost to qualify each welder with destructive testing, estimated at $5,000 - $9,000 per test.

Commission Staff has proposed in the new rules a destructive test at intervals not to exceed 27 months. The Company is not aware of such a standard being adopted elsewhere in the industry and it is substantially shorter than the 60-month requalification period the region has adopted through the NGA. During recent Chapter 500 Technical Sessions conducted prior to the official Order of Notice, Staff explained that the 27-month interval was proposed to address a concern with record keeping issues, rather than that destructive testing was necessary at 27-month

[13] State regulator participation included Connecticut, Massachusetts, Rhode Island, Vermont and New Hampshire. The Company has found no evidence that the New Hampshire representative had any concerns with the 60-month period adopted by the NGA, or that New Hampshire believed a shorter period should be adopted.

intervals to address potential degradation in welder skills. Based on the Company's actual experience, and the standards adopted in New England and other regions, it believes that a 27 months destructive testing requirement would not provide any measurable improvement in pipeline safety, would unnecessarily take New Hampshire out of step with the region on welder qualifications, and could result in unintended negative consequences to safety.

For example, Northern currently has 18 welders (contractors and Company employees) that are qualified to weld on all of its New Hampshire distribution facilities in emergency and non-emergency maintenance and construction activities. Two of the 18 welders are employed by the Company, and the remaining 16 are contractors. The Company pays directly for the qualification of its two employees. The cost for qualifying the remaining 16 contractors is essentially socialized among the operators in the region who retain and "share" these contractors to weld on their systems. Because the operators in the region use the NGA standard, the contractors' welders are essentially fungible.

If the proposed rule is adopted, New Hampshire will be out of step with the region. Welders working in New Hampshire will be forced to have expensive destructive welding tests performed more than twice as frequently as the regional norm (27 months vs. 60 months). That will result in both increased cost for the two welders that the Company employs but, more importantly, contractors will charge Northern more due to the necessity to comply with New Hampshire's unique 27-month requalification requirement. Because New Hampshire will be out of sync with the rest of the region, the added costs for more frequent destructive testing are unlikely to be socialized throughout the region as they are presently, and will be passed on directly to the New Hampshire utilities.[14]

Given: (1) the high cost of destructive testing qualifications for each welder, (2) the lack of data demonstrating that welder skills are deteriorating at a pace that requires 27-month destructive testing intervals to ensure that satisfactory welds are being performed, (3) the Company's experience that such a 27-month period is not necessary, (4) the fact that the Company is not aware of any other state that has adopted a similar 27-monty requirement, and (5) the potential negative impacts that the Company may suffer from such a regulation, the Company recommends that proposed rule be modified as follows:[15]

> *No welder shall make any pipeline weld unless the welder has qualified by destructive testing within the preceding 60 months in accordance with 49 C.F.R. § 192.227*

B. PUC 506.01(f) and (g) Calibration of Equipment.

PUC 506.01(f) and (g) are proposed new rules governing the calibration and maintenance of equipment:

> (f) A utility shall ensure the periodic inspection and calibration of all equipment, including, but not limited to, equipment used for cathodic protection, pipe jeeping, leak detection, plastic fusion, and pressure testing, which is used in construction, operations, and maintenance activities, in accordance with the frequencies defined in the manufacturers' procedures and specifications.

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[14] Alternatively, the contractors could decide that complying with the New Hampshire special regulation is too costly, and focus their business on other states. In that case, the Company would likely be required to hire, train and qualify additional employees under the unique New Hampshire requirement to ensure the availability of an adequate number of qualified welding personnel to respond to an emergency situation.

[15] If the Commission has lingering concerns that the regionally adopted 60-month standard is too long between destructive tests, Northern suggests that the Commission bring the issue to the NGA Welding committee and work with regional stakeholders to pursue the adoption of a regional standard that requires more frequent testing.

> (g) Utilities shall attach inspection stickers to all such equipment under (g) above [sic], indicating the date of the most recent inspection and/or calibration. In the event, an inspection sticker is not legible or has become detached, the operator shall make available upon request records of all periodic inspections and calibrations in the field that will adequately enable the safety division to determine appropriate calibration of equipment.

Northern believes that the safe construction, operation and maintenance of the distribution system require that all equipment used for these purposes be well maintained and calibrated in accordance with manufacturer's recommendations. Therefore, Northern agrees fundamentally with the objectives of the proposed rule. Northern is concerned, however, with the portion of the rule that states: "Inspection stickers shall be attached to all such equipment, indicating the date of the most recent inspection and/or calibration."

First, some inspections occur so frequently that attaching a new sticker each time a piece of equipment is inspected is overly burdensome and would serve no purpose for improving pipeline safety. For example, heat fusion procedures for plastic pipe requires that a "*pyrometer or other surface temperature measuring device should be used before the first joint of the day and periodically throughout the day.*" The rule, as proposed, would require construction and maintenance crews to be attaching numerous stickers during the day, which is overly burdensome and would do little to improve public safety.

Second, Inspection stickers may be difficult to keep attached to a piece of equipment that is used in the field for routine construction, operation and maintenance activities. The environment where this equipment is used is dirty, greasy and dusty. Even recently applied stickers are likely to "fall off" during use in the field. This exposes the Company to code violations and enforcement actions simply because a sticker “fell off,” notwithstanding that the equipment was recently calibrated per manufacturer recommendations.

Subpart (g) attempts to cure the detached sticker problem by requiring the Company to produce in the field, upon request, records of all periodic inspections and calibrations that will enable the safety division to determine appropriate calibration of equipment. The problem with this requirement is that the technician is now required to maintain in the field the calibration data for the equipment in the event the sticker falls off. To avoid confusion, there should only be one set of calibration records maintained by the Company, and the Company believes that those are best kept at the office, not in the field with the equipment where they are prone to being lost or destroyed.

The Company agrees that equipment should be calibrated and maintained in conformance with the manufacturer’s recommendations. And, if the Commission’s safety division has a question about when a particular piece of equipment was last calibrated, then it should be able to inspect records demonstrating compliance. But requiring stickers on equipment, and then requiring technicians to carry calibration records with them in the field is not a reasonable burden to impose.

For these reasons Northern suggests that the proposed rule be modified as follows:

> *(g) A pipeline operator shall ensure the periodic inspection and calibration of all equipment used in construction, operations, and maintenance activities. Calibrations shall be in accordance with the frequencies defined in the manufacturers' procedures and specifications. The operator shall maintain records of all periodic calibrations and make them available for inspection upon request by*

regulatory agencies.

C. **PUC 506.01(l) Multi Service Line Installations.**

PUC 506.01(l) is a proposed new rule that requires installing identification markers on multi-service installations:

> (l) Gas service line valves at multi-service installations shall be plainly marked by permanent means designating the building or part of the building being served, in accordance with the following:
>
> (1) If marking of the meter will readily identify its service line valve, the meter may be marked in lieu of the service line valve;
>
> (2) Each customer meter, gas regulating station or any above ground transporting facility shall be permanently marked to identify the operators name and phone number; and
>
> (3) Marking of facilities shall be accomplished by metal signs, line markers, plastic decals, or other appropriate means.

506.01(l)(1)

Northern recommends that 506.01(l)(1) not be adopted due to the significant cost of compliance and the lack of commensurate improvement in public safety.

Each gas service line in Northern's asset management system is assigned a unique Service I.D. number, which is then associated with a physical address. Each customer meter in the Northern Customer Information System ("CIS") is assigned a unique Location I.D. The Location I.D. is associated with a specific Service I.D., and therefore a complete association can be made between a service line and all meters served by that service line.

The proposed rule would require that a contiguous building (*e.g.*, a strip mall, duplex or condominium complex) with more than one service line have each service marked and tagged to identify which portion of the building it feeds. Northern is concerned with the cost to implement this rule because data does not exist in the Northern CIS that identifies multiple service addresses that may be part of a contiguous building. For example, the CIS may have customers with Location I.D.'s corresponding to 2 Oak Street, 4 Oak Street and 6 Oak Street. Northern's CIS does not track whether those three Location I.D's are separate free-standing buildings or a single contiguous building. If the proposed rule were adopted, Northern would need to use a two-stage method to achieve compliance. During "Stage 1" Northern would perform a full system field audit of all service lines on its distribution system to identify all services that feed a contiguous building. During "Stage 2" Northern would positively identify service line supply points and then perform the necessary tagging.

To meet the requirements of the proposed rule, a large scale mobilization of resources would be required that would supplant other important operations and maintenance efforts. Northern has developed preliminary cost estimates for this proposal in excess of $100,000 and would require a significant amount of time to achieve compliance.

A comment was made during the October 19 public hearing by Mr. Cyr of the Fire Marshall's office in support of this proposed rule. Mr. Cyr suggested that this tagging requirement would aid first responders in being able to shut of select portions of a building in emergency situation. Based on Mr. Cyr's comments, Northern is concerned that the proposed tagging requirement may create an unwarranted and false sense of security. In other words, Northern believes that in an emergency situation involving connected buildings, it is a better practice to shut off gas to the entire building, rather than attempting to section it off and running the risk that there will be no incident in the portion of the building where gas still flows.

A brief description of Northern's emergency response procedures helps illustrate the point. The primary objective of Northern's emergency response program is to minimize the hazards from potential natural gas emergencies. Our responders are trained to: first, protect human life; second, protect property; third, ensure continuity of service to customers on the distribution system. When our technicians respond to an emergency gas leak and encounter dangerous gas level readings in a building, they evacuate all occupants immediately (we protect people first) and shut off the gas to the <u>entire building</u> by the safest and fastest means possible, which is usually a master shut-off valve located at the service riser (we protect property second). When those two primary objectives have been met, the technician then addresses continuity of service.

The objective of the rule as proposed, and Mr. Cyr's desire, is to have the ability to shut off gas to only portions of a building in an emergency situation. The problem with that approach, however, is that it elevates maintaining continuity of service over the other, more important, interests. Moreover, the reality of many gas leak situations is that it is impossible to identify, with precision, the exact source of the leaking gas. And, just because gas readings are coming from one portion of a building, that does not guarantee that that the service line for that part of the building is the source of leaking gas. So, turning off the gas to <u>only</u> the portion of the building where the gas leak is <u>suspected</u> to be located is not a safe practice, and providing a means of easily sectionalizing a connected building may provide emergency responders with a false sense of security.

Due to the complex nature of this issue, and the Company's strong belief that the proposed rule will in fact be detrimental to public safety, Northern cannot recommend alternative rule language that would address all of our concerns. We recommend that PUC 506.01(l) not be enacted, and that the Commission Staff, Fire Marshall's office, and gas operators meet to discuss the relevant issues. If the Commission disagrees with Northern's position and adopts the rule we will comply as required, but will also provide formal notification to all fire departments in our jurisdiction that we do not believe that shutting off gas to only a portion of a building in emergency situations is in the best interest of public safety and we will not be responsible for any loss of life or property that may result from this practice.

<u>506.01(l)(2)</u>

Northern also has concerns with section 506.01(l)(2) which requires that " *Each customer meter, gas regulating station or any above ground transporting facility shall be permanently marked to identify the operator's name and phone number*." Currently, Northern has signage at all district regulator stations; gate stations and other above ground facilities (*e.g.*, line markers). However, we currently have approximately 29,000 customer meters that do not meet this requirement. To retrofit the meters for all of these customers as a stand-alone program would cost approximately $100,000. Northern has been unable to identify a significant or measurable improvement to public safety that would reasonably be achieved by the adoption of the proposed rule, and has significant concerns that the resources necessary to comply with the proposed rule could be better allocated to address risk as identified through DIMP Risk Analysis. Moreover, Northern has an aggressive Public Awareness program and is not aware of any instances where a customer has been unable to contact us because our name and phone number were not displayed on their meter.

This is another example of prescriptive regulation that results in increased ratepayer costs to "fix" something that is not broken. Having said that, Northern believes that the proposed rule can be modified to provide Staff with their desired meter identification, and with only a minor ratepayer impact:

> Each customer meter installed after June 1, 2013, gas regulating station or any above ground transporting facility shall be permanently marked to identify the operators name and phone number; and

This suggested approach would allow the Company to retrofit the system over time, during the normal course of business, and strikes a reasonable balance between ratepayer cost impact and Staff's objective.

D. <u>PUC 506.01(m) Telemetering.</u>

PUC 506.01(m) is a proposed new rule that requires the installation of telemetering equipment at all single feed distribution systems:

> (m) Each single fed distribution system shall be equipped with telemetering or recording pressure gage or gages as may be required to properly indicate the gas pressure in the system at all times. At least once each year the pressure variation shall be determined throughout each system. Telemetering shall be the sole method to properly indicate the gas pressure at all times for each single fed distribution system by January 2016.

The Federal regulation that governs the installation of telemetering or recording gages on single feed distribution systems is 49 C.F.R. § 192.741(b):

> On distribution systems supplied by a single pressure regulating station, the operator shall determine the necessity of installing telemetering or recording gages in the district, taking into consideration the number of customers supplied, the operating pressures, the capacity of the installation, and other operating conditions.[16]

Under the federal regulations, the operator is responsible for determining the necessity of installing telemetering and/or gauges on single feed systems. The Commission's proposed rule, which would mandate installation of telemetering or recording pressure gages regardless of the circumstances, and require a complete migration to telemetering by January 2016, is a significant departure from the current code.

Northern currently operates 22 single-feed systems. Three of those systems are currently equipped with telemetry that communicates with our central SCADA system and the remaining 19 are equipped with pressure recording charts. Northern estimates that the cost to install SCADA at a single station is in the $30,000 to $40,000 range, with a total project cost estimated at $800,000. Unlike the federal regulation, the proposed rule fails to take into consideration that each single-feed system is unique and has its own risk profile. The prescriptive requirement that telemetering be installed at all single-feed systems, regardless of its circumstances, takes a "one-size-fits-all" approach and does not recognize the diversity among these systems. For example, Northern's System 44 is a single-feed system that provides service to three customers. System 2, by contrast, feeds 914 services and over 1,000 customers. The diversity between these two systems naturally warrants different monitoring

[16] Section 192.741(b) is a textbook example of how performance-based regulation can be written to provide the operator room to maneuver within the standards adopted by the regulator. The rule identifies the factors that the operator must take into consideration when determining the necessity of installing telemetering or recording gages.

approaches for each.

Instead of a prescriptive requirement as proposed, Northern recommends an approach that provides operators an appropriate degree of flexibility to avoid the commitment of significant resources that may not be commensurate with risk:

> *(m) Each single fed distribution system shall be equipped with telemetering or recording pressure gage or gages as may be required to properly indicate the gas pressure in the system at all times. At least once each year the pressure variation shall be determined throughout each system.*

During the Public Hearing, Commission Staff alluded to an over-pressurization event on Northern's system as justification for the "one-size-fits-all" SCADA requirement. Northern fundamentally disagrees with Staff's conclusions and in fact believes this incident highlights that there are differences between systems and thus supports Northern's position that operators should have risk mitigation plans tailored to their unique systems. Although Staff did not identify the over pressurization event, Northern believes it occurred during the winter of 2004-05 at Forest Avenue, Plaistow, System No. 1. This is a delivery point from the Tennessee Pipeline to the Granite State Pipeline, and then from Granite State to Northern Utilities. The over-pressurization was caused by a freeze-up on the primary and secondary regulators with other key factors that must be considered in the analyses:[17]

- Tennessee inlet pressure: 750 psig
- Northern Utilities' delivery pressure MAOP: 60 psig

[17] This event occurred prior to Northern taking ownership of Northern Utilities and the information presented on the incident was gathered through interviews of current Northern technicians and supervisors who were directly involved in the event.

- ~50°F drop in the temperature of the natural gas due to pressure reduction[18]
- No regulator station heat
- High moisture content of the gas
- Cold ambient temperature

This event was a freeze-up on this system caused by a variety of factors, but a significant contributor was the fact that the temperature of the gas was reduced by approximately 50° through pressure reduction alone, and coupled with the low ambient temperature and high moisture content of the gas, a "perfect storm" was created.

Examining this over pressurization from a risk mitigation perspective, one solution would be to install SCADA. SCADA, however, does not prevent over pressurization from occurring. It only identifies an event when it happens. A better course of action is to take measures to avoid another freeze-up by installing line heat, pilot heat or other catalytic style heat at the station. Staff's expensive SCADA solution to this problem will not address the underlying problem.[19] It does, however, divert money away from fixing the underlying issue or addressing a higher risk identified in the Integrity Management process.

Additionally, under the proposed prescriptive rule, all regulator stations are assumed to have an identical risk profile, and therefore all are subject to identical

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[18] The Joule–Thomson effect describes the increase or decrease in the temperature of natural gas when allowed to expand freely through a valve or other throttling device (*e.g.*, regulator). For every 100 psig reduction in pressure, a corresponding 7°F reduction in temperature occurs.

[19] After Unitil acquired Northern, full station heat was installed at this regulator station. Although Northern was not able to obtain detailed cost information for that project at the time these Comments were filed, $100,000 is a reasonable cost estimate. Staff's SCADA requirement for this station alone would have funded approximately 30-40% of the cost to fix the underlying issue.

requirements in the name of public safety. Northern disagrees with this assumption and emphasizes that the risk profile of each station is different, and sound engineering and operational experience can identify specific risks and mitigate them more effectively and efficiently than a prescriptive rule. For example, Northern's System 44 is a single feed station that serves three customers. This system has upstream inlet pressure of 175 psig and a downstream MAOP of 60 psig, so the Jules-Thompson effect produces a modest 7°F temperature drop due to pressure reduction. The risk to a station with a 7° temperature drop is significantly lower than one that experiences a 50° temperature drop. Logic dictates that these stations be operated and maintained as their individual circumstances dictate.

Again, Northern has estimated that it would cost approximately $800,000 to install SCADA at all remaining single feed system and we believe that a tailored risk mitigation plan would be a better way to allocate those dollars. If the Commission is concerned that it cannot enact a performance-based regulation that will pass legislative muster, then one option to consider is to rely on the federal standard and not adopt a separate state requirement that will increase ratepayer costs without a corresponding improvement in public safety.

IV. <u>PUC 506.02 Construction, Operations and Maintenance.</u>

A. <u>PUC 506.02(e) Pipeline Installation Notification.</u>

PUC 506.02(d) is a proposed new rule that would require operators to notify the Commission ten days in advance of all new proposed construction or replacement projects if the pipe will operate at pressure greater than 60 psig:

(d) Gas pipelines (new proposed construction or scheduled replacement)

> which are to be operated at a pressure greater than 60 pounds per square inch gauge shall not, be installed under roads, public waters or railroad crossings without notification to safety division 10 days prior to construction of the crossing and vicinity.

Northern has two concerns with the proposed rule. First, it would limit an operator's ability to replace and/or install pipe in an emergency situation. In certain emergency circumstances (*e.g.*, third party damages) the only reasonable option is to replace the damaged section of pipe and this provision would preclude this construction for a period of ten days, which could disrupt service or negatively impact safety.

Second, the implementation of pipe replacement projects and construction schedules are often changing as a result of circumstances beyond an operator's control, such as changing municipal project schedules. A ten day waiting period may not provide the utility the flexibility needed to implement construction projects in an effective manner and meet the needs of our municipal partners.

For these reasons Northern proposes that the rule be modified as follows:

> *Except in emergency situations, gas pipelines (new proposed construction or scheduled replacement) which are to be operated at a pressure greater than 60 pounds per square inch gauge shall not be installed under roads, public waters or railroad crossings without notification to the Commission's safety division at least 5 days prior to construction of the crossing.*

B. <u>PUC 506.02(t) Operator Qualification Plans.</u>

PUC 506.02(t), as proposed, would enact a new Operator Qualification plans requirement:

> (5) Operator Qualification plans shall list all covered tasks and include specific abnormal operating conditions for each task. All operator qualifications covered tasks shall be cross referenced with applicable

construction standards or specifications or applicable operation and maintenance activities including emergency response.

Before providing specific comments on this proposed rule, Northern notes that NGA Written Plan Revision I, which is currently in development with an anticipated 2013 implementation, does meet the requirements of *"Operator Qualification plans shall list all covered tasks and include specific abnormal operating conditions for each task"* and Northern will implement NGA Written Plan Revision I upon its completion. If the current revisions to the NGA Written Plan Rev I are not deemed sufficient, then Northern has significant concerns with this proposed rule because it is not justified by any record of evidence and will likely have a negative impact on public safety and mutual aid.

The Federal regulations governing Operator Qualification ("OQ") are at 49 C.F.R. § 192, Subpart N, "Qualification of Pipeline Personnel." The Department of Transportation's ("DOT") Operator Qualification final rule went into effect on October 26, 1999. The rule required operators to: (1) develop and maintain a written qualification program for individuals performing covered tasks; (2) implement the program by April 27, 2001; and (3) complete the qualifications of all personnel performing covered tasks by October 28, 2002. The objective of imposing operator qualification requirements is to minimize human error by establishing a verifiable, qualified workforce. In other words, OQ is a safety initiative that uses operator training to reduce the risk of pipeline incidents caused by human error.

The development of Northern's OQ Program included participation in a consortium of 36 distribution companies from the six New England states and New York. The program development was administered through the NGA and the New York

Gas Group. During the development of the program, and every year thereafter, the NGA has solicited feedback from all State Regulatory Authorities on the program and suggested improvements based on that feedback. The NGA regional plan is re-evaluated annually and, since its inception in October 2000, the program has been revised and improved eight times demonstrating a philosophy of continuous evaluation and improvement.

There are several advantages to all of the regional distribution system operators participating in the NGA program. Having the input of many operators ensures that issues are identified, carefully evaluated, and acted upon as appropriate. In addition, there are advantages to having worked within the consortium and having developed OQ plans that, while not identical among the operators, share common objectives and standards. This commonality is highly beneficial to the Company, as well as other operators in the region, particularly when participating in mutual aid efforts, certifying contractors to work on our system, and performing qualification testing and associated record keeping.

Northern is deeply concerned with the language in the proposed rule that mandates: *"Operator Qualification plans shall list all covered tasks and include specific abnormal operating conditions for each task."* While this single sentence may seem innocuous, it is likely to have unintended consequences that would negatively impact Northern's operations and disrupt the neat and orderly system of operator qualification that the region has worked so hard to develop in conjunction with the NGA. The development of task specific abnormal operating conditions ("AOC's") in addition to the eight AOC's currently recognized by the NGA is a substantial deviation from the NGA regional program and in essence would require Northern to adopt a “different program” than what the other distribution operators and contractors use as the regional standard. This would impact the following:

1. Contractors: All contractors working on the Northern system are currently required to be Operator Qualified under the NGA regional program. In addition, the Company must verify that the contractor’s OQ program is compatible with our own qualification procedures, including the recognition of and reaction to AOC’s identified by the operator (See PHMSA OQ FAQ 1.3, below). If Northern is required by the proposed rule to develop task-specific AOC’s that differ from the established NGA AOC’s, then Northern would be prohibited from recognizing the current NGA program because it would no longer be compatible with our new “different program” imposed under New Hampshire law. Northern bases this conclusion on the following PHMSA OQ FAQ 1.3:

> **PHMSA FAQ 1.3.** Will contractors be required to have a written OQ Program?
>
> **Answer:** Only pipeline operators are subject to the requirements of the DOT Rules. Individuals performing covered tasks on an operator's pipeline facility, including its own employees, contractors, sub-contractors, original equipment manufacturers (OEM) representatives, temporary help, etc., must be qualified or perform covered tasks under the direct supervision of a qualified individual. Operators may require contractors which supply individuals to perform covered tasks to:
>
> a. Have their own OQ Program and provide documentation that these individuals are currently qualified to perform the assigned covered tasks.
>
> b. Belong to a Consortium which provides the required qualification evaluations and documentation, or
>
> c. Qualify those individuals under the Operator's own OQ Program; or
>
> d. Have an independent third party evaluate their qualification and provide the required documentation.
>
> **Whichever alternative is chosen, the contractor must be operating under an OQ Program that the operator has verified as being compatible with its own qualification procedures, including the recognition of and reaction to AOCs identified by the operator.**

If the proposed rule were adopted, Northern would be required to establish a new testing protocol for all contractors prior to allowing them to work on our system.

2. Mutual Aid: The proposed deviation from the NGA regional plan would also preclude Northern from relying on emergency mutual aid with other operators that qualify individuals through the NGA regional plan. Northern currently has mutual aid agreements with all other operators in the NGA and our Emergency Procedures specify the use of these mutual aid agreements during system emergencies. During a system emergency, Northern would be required to test and qualify mutual aid personnel prior to deployment that would likely delay emergency response and cause needless risk to property and human life. Northern bases this conclusion on PHMSA FAQ 1.9:

    PHMSA FAQ 1.9 What requirements exist related to the qualification of persons participating in mutual assistance agreements?

    Answer: Mutual assistance agreements are typically designed to clarify the conditions under which pipeline operators support each other in the safe restoration of services following a significant outage. **It is the responsibility of the operator whose system is being restored to ensure that all individuals performing covered tasks pursuant to mutual assistance agreements are qualified in a manner consistent with the operator's OQ Program requirements (also see FAQs 1.6 and 1.8).**

3. Qualification Testing: Northern currently has 84 identified covered tasks in our OQ written program. Each one of these tasks qualifies individuals through a written examination and hands on test, when applicable. Qualification in any task, as defined by 49 C.F.R. § 192.803, requires the individual to be evaluated to: (1) perform the assigned covered tasks; and (2) demonstrate the ability to recognize and react to abnormal operating conditions. If Northern is required to develop task specific AOC's, then all of the current examinations would be inadequate to meet this requirement and new tests would need to be developed and validated, which would be an expensive endeavor.

As discussed above, the purpose of an OQ program is to reduce human error as the cause of pipeline safety issues through the establishment of a verifiable, qualified workforce. One method of assessing the effectiveness of our established OQ program is to quantify the number of incidents that were caused by human error. While human error can never be completely eliminated, Northern takes great pride in the quality and efficacy of our training and qualification programs and we experience few incidents that are caused by human error. In fact, during 2011, as reported on PHMSA Form 7100-1.1 report, there were no incidents caused by human error. Therefore, we do not believe that changes to our regionally-based OQ program should be required in the absence of evidence that our current program does not meet safety objectives and that the advantages to any new requirements will outweigh the disadvantages that Northern has identified here.

Due to the complex nature of this issue and potential consequences, Northern recommends a two phase approach with the first being alternative language to Rule 506.02(t) as follows:

> *Operator Qualification plans shall list all covered tasks. All Operator qualifications covered tasks shall be cross referenced with applicable construction standards or specifications or applicable operation and maintenance activities including emergency response.*

The second phase to Northern's recommended approach is to address any additional concerns that the Commission or Staff may have concerning OQ programs in the context of the NGA framework to develop a better understanding of Staff's concerns and consider the implementation of measures to address those concerns in a concerted effort on a regional basis.

C. <u>PUC 506.02(u) Quality Assurance/Quality Control Plans.</u>

Section 506.02(u) is a proposed new rule concerning Quality Assurance and Quality Control plans that would require the following:

> (u) Construction Quality assurance plans shall be written, followed and documented as follows:
>
> (1) Each utility shall inspect any new construction by outside contractors

that is or will be incorporated into the utility's system to verify that the resulting installation meets company specifications.

(2) A representative number of field verification audits shall be conducted after field work is completed for specific tasks;

(3) Performance Audits shall be conducted to evaluate a representative sample of various tasks are evaluated during the actual time that the work is being performed by the employee or contractor;

(4) Construction Inspections that are frequent enough to encompass most of the new facility installation and repairs that are done on the utility system.

(5) Detailed forms incorporating activity checklists prepared to cover normally performed work activities for evaluation or inspection of specified field work and construction.

(6) Audits of employees and crews shall be conducted by management personnel (e.g., supervisors, engineers) to ensure that all personnel have reviewed the quality assurance plan and that all construction work is inspected on a regular basis; and

(7) Utilities shall take remedial action within 3 months to correct or make substantial progress toward correction of any deficiencies indicated by construction quality assurance audit and inspection findings.

Northern agrees that a rigorous QA/QC program is essential for ensuring safety of the gas distribution system and compliance with 49 C.F.R. § 192.605. Our current QA/QC protocol meets the requirements of the proposed rule. Northern does, however, have significant concern that some portions of the rule intrude unnecessarily on the day-to-day operation and management of the Company. Each utility operates a unique system that faces its own set of operational challenges and risks. As the federal DIMP requirements acknowledge, the owners and operators of those systems are best positioned to develop their own internal programs tailored to meet the Commission's objective of ensuring compliance. Northern suggests that the rule require operators to establish QA/QC programs (*i.e.*, what should be done) and allow the operators to establish programs to achieve the objectives that are tailored to their specific circumstances. Of course, the Commission and its gas safety staff have the authority to audit each operator's specific program to ensure compliance with the Commission's rules, and Northern would be receptive to discussing any concerns or suggestions that the Commission or its staff may have with the Company's program.

Northern believes that this approach would be more effective in achieving the Commission's safety goals across each operator's unique system and avoids trying to adopt an effective one-size-fits-all approach. For these reasons Northern proposes that PUC 506.02(u) be adopted as follows:

> *(u) Each natural gas utility must, as part of its compliance with 49 C.F.R. § 192.605 (procedural manual for operations, maintenance, and emergencies), include procedures for evaluating the work performed by utility personnel to determine the effectiveness and adequacy of the procedures used during normal operation and maintenance tasks and to modify the procedures when deficiencies are found. Such procedures shall be set out in a written Quality Assurance and Quality Control Program (QA/QC) that promotes gas system and related employee and contractor safety through monitoring of field work activities performed during the construction, installation, operation and maintenance of gas facilities. The utility shall also develop a construction inspection program for new construction and facility repair work performed by utility employees and by contractors as part of the QA/QC Program.*

Alternatively, if the Commission concludes that a performance-based regulation may encounter legislative resistance, then the Commission can rely on the federal regulations that govern QA/QC programs and not enact a separate, prescriptive state law requirement.

D. PUC 506.02(v) Remedial Action on Cathodically Protected Pipelines.

PUC 506.02(v) is a proposed new rule that would require remedial action on certain cathodically protected pipelines:

> (v) Each utility must take remedial action within three (3) months to correct or make substantial progress toward correction of any deficiencies indicated by monitoring of cathodically protected pipelines.

The Federal Code requires the monitoring of cathodically protected pipelines under 49 C.F.R. § 192.465 (and the remedial actions to correct any deficiencies under subpart (d)) as follows:

> (a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.
> (b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1/2 months, to insure that it is operating.
> (c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2 1/2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.
> **(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.**

As stated in subpart (d), the Federal Code requires "prompt remedial action" to correct any deficiencies, but does not define "prompt." Northern utilizes the Gas

Piping Technology Committee ("GPTC")[20] guidance material for determining appropriate corrective action to deficiencies in cathodically protected pipelines for the Northern system. The action criteria developed by GPTC are considered by the industry to be a best practice and standard for natural gas operators. The guidance material provided by GPTC for remedial action to correct deficiencies found by monitoring is as follows:

> (a) Common corrosion control methods include coating, CP, and electrical isolation. CP systems typically use galvanic anodes or impressed current (rectifiers). Other corrosion control devices may include electrical isolators, interference bonds, diodes, and reverse current switches.
> (b) Remedial action is required whenever it is determined that the CP or other installed corrosion control methods are not operating effectively.
> (c) The specific remedial action to be taken depends on the type of corrosion control method installed and the problem encountered. In certain situations, the deficiency can be corrected by modifying existing corrosion control methods (e.g., increasing output from adjacent rectifiers).
> **(d) Operators are required to take prompt remedial action to correct deficiencies indicated by monitoring. Remedial action should correct the deficiency before the next monitoring cycle required by §192.465. However, for monitoring cycles greater than one year, remedial action should be completed within 15 months of discovery.** Example: It is discovered that pipe coating has deteriorated and that the existing corrosion control system is unable to achieve the desired CP level. The operator should initiate and document action taken to achieve the acceptable CP level before the next monitoring cycle. Remedial action might include the following.
> (1) Installing additional CP,
> (2) Recoating the pipe to meet the requirements of §192.461, or
> (3) Replacing the pipe.
> **(e) If remedial action cannot be completed prior to the next scheduled monitoring cycle, the operator should document the actions taken to correct the deficiency and the expected timeframe**

[20] GPTC is an independent technical committee accredited by the American National Standards Institute ("ANSI") as ANSI/GPTC Z380.01. The GPTC provides guidance to assist natural gas operators with the implementation of pipeline safety programs in compliance with federal regulations.

for completion.

The GPTC is universally recognized by the gas industry and PHMSA as the organization to provide guidance on implementing pipeline safety programs.[21] Northern believes that the Company's current corrosion control program, which complies with federal mandates, is effective. We attribute its success, in part, to our utilization of the GPTC guidance as a foundation of our program. We also believe that any substantial deviation from our current program should be based on a demonstrated likelihood that the deviation will result in improved safety. At this time no evidence has been presented that indicates a change to the program would improve pipeline safety.

Given the Company's reliance upon guidance materials that are widely accepted as a best practice in the industry, Northern does not believe that changes should be initiated without clearly documented studies or other reliable data demonstrating that the current GPTC-based programs are not effective or result in unsafe operating conditions. Northern is not aware of any such studies or data, and requests that if other operators or authorities know of such evidence or information that it be shared with others in the industry so it may be properly assessed.

In the absence of such evidence or information, Northern strongly recommends that any proposed corrosion remediation requirements hew to the standard developed by GPTC. The GPTC's guidance is recognized as an industry best practice and there is no study or data of which Northern is aware concluding that a measurable increase in

[21] As an example of how highly GPTC is regarded, after publication of the December 2005 "*Report on Integrity Management for Gas Distribution*," PHMSA asked the GPTC to develop the guidance material for the regulation prior to the rule being written.

public safety would be achieved by adopting new regulations that would depart significantly from GPTC's guidance. For these reasons Northern recommends that the proposed rule be modified as follows:

> *(u) Each utility must take prompt remedial action to correct any deficiencies indicated by monitoring of cathodically protected pipelines. Remedial action should correct the deficiency before the next monitoring cycle. However, for monitoring cycles greater than one year, remedial action should be completed within (15) months of discovery. If remedial action cannot be completed prior to the next scheduled monitoring cycle, the operator should document the actions taken to correct the deficiency and the expected timeframe for completion.*

V. PUC 508.04 Leakage Surveys and Inspections.

A. PUC 508.04(m) Leak Grading and action criteria

Federal Integrity Management requirements imposed by 49 C.F.R. § 192.1007(d) require that operators have an effective leak management program:

> Identify and implement measures to address risks. Determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. **These measures must include an effective leak management program** (unless all leaks are repaired when found).

Northern believes that effective leak grading and action criteria are the foundation of an effective leak management program and therefore have already implemented a program that aggressively identifies, classifies and repairs gas leaks. Currently, Northern assigns grades to below ground leaks as follows:

- Grade 1 Leak – a leak that represents an existing or probable hazard to persons or property, and requires prompt action, immediate repair, and/or continuous action until the conditions are no longer hazardous.
- Grade 2 Leak – a leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair or removal based on the probability of future hazard.

- Grade 3 Leak – a leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.

Northern grades above ground leaks using two categories of "hazardous" and "Non-Hazardous" as follows:

a) A hazardous above ground leak is an unintentional escape of gas from above ground piping or related gas facilities that require immediate make-safe action, because:

(1) On outside piping it can be seen, heard or felt (*e.g.*, causes the blowing off of leak detection soap); and is in a location that may endanger the general public or property (*e.g.*, requires an immediate evacuation to protect public safety).

(2) On inside piping it can be seen, heard or felt (*e.g.*, causes the blowing - off of leak detection soap) and/or has sustained positive gas readings as indicated by a combustible gas indicator.

(b) An above ground leak is reportable when it is hazardous based on the criteria defined above and the source of the leak is identified as jurisdictional piping. Documentation for hazardous above ground leaks should follow the same protocol as below ground leaks.

(c) Minor escapes of gas (non-hazardous releases) at threads on sound piping or at fittings that are detectable only with instruments in direct proximity or that give only slight indications with leak soap are not reportable leaks if they could be eliminated by lubrication, adjustment or tightening, even if the repair methodology is the reconstruction or replacement of parts. These leaks will be categorized as 'Fit Leaks' and documented as such.

Northern used the GPTC guidance as a foundation for developing our leak management program, but then analyzed our unique circumstances to develop a company-specific leak management program that we believe is one of the most aggressive in the region and meets the primary objective of protecting public safety. This program took a year to develop and was implemented in May of 2012, identified as Section 2-N "Leak Management" of our Operating & Maintenance Procedures.[22]

[22] A copy of the Company's leak management program is provided as Attachment D.

Northern's current leak classification procedures are similar to those proposed under Section 508.04(l). Nevertheless, the Company does have some concern with the prescribed gas percentages as proposed in the rule.

The majority of the lower explosive limit ("LEL") percentages used in the proposed rule for leak classification are significantly lower than the GPTC guidance and Northern's current standards. A few examples follow:

- Northern considers a gas reading in a confined space of 70% of the LEL[23] a Grade 1 leak. Under the proposed rule this threshold would be reduced to 40% of the LEL. Northern believes that its current classification standards, which are more stringent than GPTC guidance, vigilantly protect public safety and commission staff has not presented any evidence that supports the 40% LEL proposal.

- A Grade 2 leak, by definition, is a leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on the probability of a future hazard. The probability of Grade 2 leaks becoming a hazard is not identical from leak to leak and therefore all Grade 2 leaks should not be treated the same. Northern currently has a procedure for ranking and prioritizing repairs for all Grade 2 leaks. Northern believes that this is an industry best practice and that the failure of the proposed classification criteria to recognize this reality is an inherent weakness.

- As mentioned above, Northern's leak classification program recognizes the difference between a gas leak that is on an above ground facility with unobstructed ventilation to atmosphere as compared to one that is below ground and the risk profile resulting from gas migration is significantly different. The proposed rule does not distinguish between the two which Northern again views as a fundamental weakness and an issue that could lead to confusion.

- The proposed rule requires operators to re-evaluate Grade 3 leaks on six month intervals and departs from the GPTC guidance[24] recommending intervals during the next scheduled survey or not to exceed 15 months. Northern currently reevaluates Grade 3 leaks at intervals not to exceed 12 months and does not believe that changing the interval is warranted based on its experience and industry best practices.

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[23] The LEL of natural gas is considered to be a gas in air concentration of 5%.

[24] Leak grading and action criteria guidance material, as detailed in GM Appendix G-192-11. *Gas leakage control guidelines for natural gas systems* is provided as Attachment E.

Northern believes that leak classification and action criteria are the cornerstone of all leak management programs and that they should be modified only after a firm conclusion can be reached, based on a record of evidence, that such modification will substantially improve public safety. Northern believes that Commission Staff and the New Hampshire operators have begun to have meaningful dialogue on leak classification, but two or three brief meetings are insufficient to ensure that any changes are adequately vetted, will result in improved public safety, and are cost-justified. More is not always better, and revisions to leak classifications could lead to an allocation of pipeline safety resources that is not commensurate with risk.

Do to the complex nature of this issue and the lack of a developed record of evidence, Northern cannot recommend alternative rule language that would address all of our concerns. Therefore, the Company recommends that PUC 508.04(m) not be enacted and that the operators and Commission Staff continue to meet and to develop language that addresses public safety.

If the Commission decides to adopt the proposed rule, Northern estimates that it would cost between $20,000 and $30,000 to adopt a unique New Hampshire procedures manual. Currently, the Company uses electronic Pipeline Safety Procedures that are common to all three of our local distribution operating centers and allows us to take a best practice approach for all three states. The cost of producing these common procedures is socialized among the three distribution systems. The estimate we have provided is to produce and implement unique leak grading standards for our New Hampshire operations.

B. PUC 508.04(p) Downgrading Leaks.

Commission Staff has proposed a revision to PUC 508.04(p) that prohibits downgrading a leak unless it has been repaired (shown below in black line format):

> When a leak is re-evaluated, the utility shall classify it using the same criteria as when the leak was first discovered. <u>A utility shall not downgrade a leak unless it is repaired.</u>

The proposed revision does not provide the necessary operational flexibility to account for classification errors, typographical errors and other legitimate bases for a downgrade that pose no threat to public safety. Northern has first-hand experience with a "no downgrade policy" and in a small number of instances the lack of flexibility resulted in crews digging unnecessary holes. Northern agrees with the premise that "leaks should be fixed," but does see the need for some flexibility in the application of the rule. For these reasons, Northern proposes that the rule be modified as follows:

> (p) Unless otherwise provided herein, a leak cannot be downgraded without a physical repair being made. A downgrade without a physical repair is permissible if the Operations Manager determines, after a documented investigation, that downgrading the leak would not materially increase risk of public harm. The written record of this investigation and the Operations Manager's approval of the downgrade shall be maintained by the utility.

C. PUC 509.15(e) Leak Reporting

PUC 509.15(e) is a proposed new rule that requires additional information to be provided in monthly leak reports. The additional information includes:

(1) The leak address;

(2) The date leak was reported;

(3) The identification number of the leak;

(4) The leak area (rural, residential, urban);

(5) The classification of the leak;

(6) Method of how the company became aware of leak (for example, public, employee, winter patrol);

(7) Type of cover over leak (for example, asphalt, concrete);

(8) The pipeline facility (for example, main, service);

(9) The operating pressure (for example, low, intermediate, high); and

(10) the most likely material(s) involved in any suspected Class III leaks.

Northern supports this new reporting format, but requests six months to implement necessary programming changes to our Compliance Management System to extract this data and provide it in the format required by the rule.

CONCLUSION

Northern appreciates the Commission's consideration of these Comments and looks forward to working with Staff and the Commission to develop gas service rules that strike an appropriate balance between prescriptive and performance-based regulation and maximize the efficient use of ratepayer dollars.

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ATTACHMENT A

Distribution Integrity Management Frequently Asked Questions

Revision Date: March 10, 2011

A. Excess Flow Valve Requirements

The Integrity Management Program for Gas Distribution Pipelines Final Rule included a revision to 49 CFR Part 192.383 Excess Flow Valve Installation which mandated the installation of excess flow valves (EFV) in certain new and replaced residential service lines.

A.1 Must an operator install an EFV in branch (split) service lines serving single-family residences?

No. Operators are required to install EFVs in new or replaced service lines serving single-family residences. A service line serving a single-family residence means a gas service line that begins at the fitting that connects the service line to the main and serves only one single-family residence.

Operators are not required, but may choose to install EFVs in other applications as part of their risk mitigation strategy.

Last Revision: 8/2/10

A.2 Must operators retrofit excess flow valves into existing service lines?

Operators are only required to install EFVs where single family residential service lines are newly installed or are replaced for other reasons. The rule defines "replaced" as where the fitting that connects the service line to the main is replaced or the piping that is connected to this fitting is replaced. Replacement of other portions of a service line (e.g., near the meter) would not trigger the requirement to install an EFV.

Last Revision: 8/2/10

A.3 Will excess flow valves provide protection for gas line breaks on customer piping inside a residence?

EFVs required by this regulation are not designed or intended to protect against breaks or leaks on customer piping inside a home. EFVs are intended to cut off the supply of gas to the downstream service line in the event of major damage (e.g., a line severed by excavation damage).

Last Revision: 8/2/10

A.4 Where must the EFV be installed on a service line?

An operator is required to locate an excess flow valve as near as practical to the fitting connecting the service line to its source of gas supply. Examples of acceptable locations include installing an EFV that is built into the service tee, installing a short section of pipe between the service tee and the EFV to allow for the pipeline to be squeezed off upstream of the EFV, and installing an EFV out from under pavement to facilitate future access. Operators may use reasonable judgment in determining the most appropriate location for an EFV.

Last Revision: 8/2/10

A.5 Will an operator have to notify other customer classifications of the availability of excess flow valves?

No. The notification requirement was repealed.

Last Revision: 8/2/10

A.6 Since installation of EFVs is mandated for all new and replaced service lines serving single-family residences where EFVs are feasible, why do operators still need to report them?

PHMSA is required by the *Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (PIPES)* to collect this data.

Last Revision: 8/2/10

A.7 Does the operator report the number of EFVs installed per year or the total number of EFVs installed on an operator's system on the Annual Report form? Does the number include EFVs installed on services other than single-family residences?

Operators are to report the total number of EFVs installed in the system on service lines serving single-family residences and the estimated number of EFVs in their system at the end Of the year. Both metrics are reported on the Annual Report form in Part E – Excess Flow Valve (EFV) Data. Operators may, but are not required, include EFVs installed on branched services serving single-family residences in the total. PHMSA is revised the Annual Report form for the 2010 calendar year to accommodate this information.

Last Revision: 2/9/11

A.8 The regulation exempts the installation of EFVs on services which do not operate at a pressure of 10 psig or greater throughout the year. Can you give examples of types of documentation that would be acceptable in demonstrating this issue?

Two possible methods to demonstrate that services operate at a pressure less than 10 PSIG include; (1) distribution system design documents, validated with actual pressure readings, which show that the main and therefore the associated services are designed to operate below 10 PSIG, or (2) actual pressure recordings or readings on all feeds which are upstream of the service(s) which are less than 10 psig.

Last Revision: 8/2/10

B. General Distribution Integrity Management Program Questions

B.1 DIMP Fundamentals

B.1.1 Why did PHMSA mandate integrity management requirements for distribution pipeline systems?

PHMSA's regulations in part 192 have contributed to producing an admirable safety record. Nevertheless, incidents continue to occur, some of which involve significant consequences, including death and injury. It is not possible to significantly reduce high consequence pipeline incidents without reducing the likelihood of their occurrence on distribution pipelines. PHMSA used an integrity management approach similar to that used for transmission pipelines, with appropriate modification to reflect the different nature of distribution pipelines, to accomplish this safety improvement. These incidents often involve unique circumstances or characteristics of a particular pipeline system/ segment or its operation.

The *Pipeline Integrity, Protection, Enforcement, and Safety Act of 2006* (PIPES) mandated that PHMSA prescribe minimum standards for integrity management programs for distribution pipelines. The law provided for PHMSA to require operators of distribution pipelines to continually identify and assess risks on their distribution lines, to remediate conditions that present a potential threat to pipeline integrity, and to monitor program effectiveness. Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective given the diversity in distribution systems and the threats to which they may be exposed. Instead of imposing additional prescriptive requirements for integrity management, PHMSA concluded that a requirement for operator-specific programs to manage pipeline system integrity would be more effective.

Last Revision: 8/2/10

B.1.2 Why don't distribution integrity management requirements focus on high consequence areas?

The integrity management requirements for transmission pipelines are focused on portions of the pipeline where significant consequences could result if an incident occurs — so-called "high consequence areas". Transmission pipelines often traverse rural areas. This approach requires safety-improvement efforts to be focused on areas where consequences of an event would be more significant, in areas with greater human density, or more sensitive environment. Distribution pipelines are largely in developed, more populated areas, since they exist to deliver gas to those populations. As the population is in close proximity to much of these distribution systems, the consequences of an incident are similar throughout. For distribution pipelines, PHMSA concluded it is more appropriate that operators consider their entire pipelines under their integrity management programs**.**

Last Revision: 8/2/10

B.1.3 Why aren't distribution pipeline operators required to physically inspect their pipelines as are operators of other types of pipelines?

The assessment techniques used on hazardous liquid and gas transmission pipelines (e.g., in-line inspection, pressure testing, direct assessment) are not transferable to distribution pipe. Additionally, distribution pipelines are not subject to the same pressures as transmission pipelines and thus tend to leak rather than rupture. It is important that distribution integrity management programs be focused on identifying the conditions that can cause leaks and addressing them before the failures occur and on managing leaks effectively when and if they do occur.

Last Revision: 8/2/10

B.1.4 Have State Agencies and PHMSA communicated with operators about Distribution Integrity? What has been discussed?

States periodically host PHMSA Training and Qualifications (TQ) pipeline safety seminars for operators including those of municipal, master meters, and small LPG systems. The seminars included updates regarding proposed rules and recent final rulemakings. Communications about DIMP covered information such as the anticipated final rule date, GPTC guidance development, the purpose of the regulation, and the proposed requirements for the rule. PHMSA's Regional offices also hold safety seminars which cover new and proposed rules, current initiatives, and advisory bulletins. PHMSA and some States have and continue to speak at national and statewide operator association meetings as well as both statewide and local emergency assistance meetings.

In 2007, prior to the DIMP Notice of Proposed Rulemaking PHMSA and the States, through NAPSR, created the DIMP State-Federal Team. PHMSA and the States have been working together to advance a consistent understanding of the DIMP. We have worked jointly to identify frequently asked questions, write responses and to develop inspection forms and guidance. Our joint efforts promote more uniform and knowledgeable inspections. Additionally, PHMSA's TQ organization is working to prepare and provide timely training to state and federal pipeline safety inspectors. The group continues to meet and work together through the implementation phase.

Last Revision: 8/2/10

B.2 State and Federal Enforcement

B.2.1 How does PHMSA foresee this rule being enforced for compliance?

Inspectors will review the IM plan for quality and completeness and ensure that operators are doing what their plan says; and then inspect to see if their plan is effective. The procedures and records will be reviewed to verify that the operator performed them as written and in compliance with required dates. Enforcement will be consistent with current practice by the jurisdictional agencies.

Last Revision: 8/2/10

B.2.2 Will operators be compared against other operators or national leak or safety data?

PHMSA recognizes that operators need to develop a DIMP plan appropriate for the applicable threats, the operating characteristics of their specific distribution delivery system, and the customers that they serve. PHMSA and State partners intend to focus on each individual operator's performance trends.

Last Revision: 8/2/10

B.3 GPTC Guidance

B.3.1 Must an operator follow the Gas Piping Technology Committee (GPTC) DIMP guidelines?

No. The GPTC DIMP guidelines provide options which operators can use in implementing the high-level requirements of the rule. The GPTC DIMP guidelines are not incorporated into the rule, and thus are not regulatory requirements. Operators may use other approaches to meet the high-level requirements of the regulation as well, but in doing so they should be prepared to demonstrate to their regulators that their actions meet the rule requirements. PHMSA, State pipeline safety regulators and industry all participated in the development of the GPTC guidelines and have confidence that operators who use them in their programs will comply with the requirements of the rule.

Last Revision: 8/2/10

B.3.2 How will the GPTC guidance be used by regulators?

The GPTC Guide provides operators with valuable, consensus written guidance that can assist them in preparing their DIMP plan. The GPTC Guide is not regulation. An operator needs to follow the procedures they include in their plan. If their plan references the GPTC guidance, the regulator may verify that the operator has implemented the referenced guidance as written. However, as referenced in B.3.1 above, an operator may choose to use practices other than those in the Guide to meet compliance. The inspection is based on the regulation, not on GPTC guidance.

Last Revision: 8/2/10

B.4 SHRIMP

B.4.1 What is SHRIMP?

SHRIMP (Simple, Handy, Risk-based Integrity Management Plan) is a software application designed to assist operators in developing plans to manage the integrity of their distribution piping. It is geared toward the needs of small utilities that lack in-house engineering and/or risk management expertise. The American Public Gas Association (APGA) Security and Integrity Foundation (SIF) received funding from PHMSA for development. Contact APGA www.apga.org or the SIF www.apgasif.org for information or questions pertaining to SHRIMP.

Last Revision: 8/2/10

B.4.2 Is there a threshold size of an operator's distribution system above which the SHRIMP tool should not be used?

SHRIMP was designed to facilitate development of a distribution integrity management plan for smaller distribution systems that are not overly complex. While there is no system size or level of complexity for which use of SHRIMP is excluded, an operator must develop a plan that demonstrates to its oversight agency it has used reasonably available information to develop knowledge, identify threats, and determine how to manage system risks. Ongoing analysis of SHRIMP for larger, more complex systems indicates that these operators will very likely need to significantly expand upon a SHRIMP-generated plan to demonstrate it has used reasonably available information to understand and determine how to manage system risks. These findings are being incorporated into inspection guidance.

Last Revision: 11/10/10

C. Subpart P – Gas Distribution Pipeline Integrity Management

C.1 §192.1001 What definitions apply to this subpart?

C.1.1 What was used as a basis for defining "hazardous leaks"?

The definition for hazardous leaks was drawn from the Gas Pipeline Technology Committee's (GPTC), *Guide for Gas Transmission and Distribution Piping Systems* (The Guide) in Appendix G-192-11, Section 5.5 Leak grades. GPTC ANSI Z380 is an accredited American National Standards Institute (ANSI) standards committee that develops and publishes *The Guide* to assist natural gas pipeline operators in complying with Part 192. PHMSA's Office of Pipeline Safety (OPS) is represented on this committee. Many operators now use the guidelines to classify leaks.

Last Revision: 8/2/10

C.1.2 How was the definition "excavation damage" developed?

PHMSA's definition for excavation damage closely matches the definition used in the Common Ground Alliance's (CGA) Damage Information Reporting Tool (DIRT). CGA is a national group involving operators of all types of underground facilities, as well as representatives of excavators and others who play an important part in preventing damage to underground facilities. PHMSA has omitted the phrase ''of exposure'' used in the DIRT definition, since this refers to damage from causes other than excavation (e.g., washout).

Last Revision: 8/2/10

C.2 §192.1003 What do the regulations in this subpart cover?

C.3 §192.1005 What must a gas distribution operator (other than a master meter or small LPG operator) do to implement this subpart?

C.3.1 If an operator has both natural gas and LPG systems, must it have two separate DIMP plans or may it have a single plan?

The operator has an option. An operator may choose to have a single DIMP plan, but it must address the requirements for both types of systems. The plan must take into account the different threats associated with the different products. Or an operator may choose to have separate DIMP plans for the natural gas and for the LPG system.

Last Revision: 8/2/10

C.3.2 Must an operator have one DIMP plan covering all of its systems or could it have separate plans for different systems or service areas?

An operator may have one master plan or separate plans, so long as its entire service area is covered. However, data from multiple plans is required to be consolidated for annual reporting purposes by state.

Last Revision: 8/2/10

C.3.3 Will companies operating in several states need to develop individual DIMP plans for each state?

The operator may have a single DIMP plan for several states; however, the operator must address any additional requirements for each state since individual states may have the authority to impose additional requirements on intrastate lines the state regulates. For example, individual States may require performance measures be provided for pipe in their state in addition to the total for the operator.

Last Revision: 8/2/10

C.3.4 What is the relationship between an operations & maintenance manual and a DIMP plan?

An O&M manual contains written procedures describing how operators conduct operations and maintenance activities on their system in accordance with Federal and State pipeline safety regulations. The activities address various threats to a pipeline's integrity. A DIMP plan is a written integrity management plan which describes the analysis of the operator's system, provides a relative risk analysis based on threats to the system, and prescribes additional or accelerated actions as needed to address risks identified in the plan.

An operator may find it convenient to incorporate additional or accelerated actions, as determined to be necessary under its DIMP plan, into its O&M manual. As the operator evaluates the effectiveness of these actions, it may identify a need to modify those actions, potentially requiring additional modifications to its O&M plan. Note that States may require a revision history, a record of modifications to the O & M manual.

Last Revision: 8/2/10

C.3.5 Is there a deadline by which operators must satisfy these requirements?

Yes, by no later than August 2, 2011, operators of gas distribution pipelines, including master meter or small LPG operators, must develop and implement an integrity management program that includes a written integrity management plan. PHMSA recognizes that implementing IM plans involves learning leading to improvement and expects that programs will evolve over time as experience is gained. However, the program developed by August 2, 2011, must address all of the required plan elements.

Last Revision: 8/2/10

C.3.6 How does the new DIMP rule impact operators of gas piping systems on military bases, Federal Government, or Indian Tribal Government land?

PHMSA does not regulate pipeline systems owned and operated by the Military, Federal Government, or an Indian Tribal Government. A "person" is defined in Section 192.3 of the pipeline safety regulations as "any individual, firm, joint venture, partnership, corporation association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof." The definition of "person" does not include the "Federal Government", "Military" or "Indian Tribal Governments". Gas pipeline systems owned and operated by the Military, Federal Government or Indian Tribal Governments are exempt from compliance with the pipeline safety regulations.

However, if the system is owned and/or operated by a private entity, such as a contractor, then it must comply with the regulations under 49 C.F.R. 192. Therefore the DIMP rule also impacts gas systems on military bases, land owned by the Federal Government, or on land owned by Indian Tribal Governments if the system is owned or operated by private entities.

Last Revision: 11/10/10

C.3.7 Are operators required to include "farm taps" in their distribution integrity management plan?

In the past, distribution, gathering, and transmission operators connected landowners directly to transmission and gathering pipelines often in exchange for the right to install the pipeline across a landowner's property. This connection to the gas pipeline is commonly referred to as a "farm tap". Although new farm taps are not installed nearly as frequently as they were in the past, "farm taps" are very common. The vast majority of "farm taps" meet the definition of a distribution line given that they do not meet the criteria to be classified as a gathering line or a transmission line.

The "farm tap" is pipeline upstream of the outlet of the customer meter or connection to the customer meter, whichever is further downstream, and is responsibility of the operator. The pipeline downstream of this point is the responsibility of the customer. Some States require the operator to maintain certain portions of customer owned pipeline. The pipeline maintained by the operator must be in compliance with 49 Part 192.

Operators of distribution, gathering, and transmission lines with "farm taps" must have a distribution integrity management program meeting the requirements of Subpart P for this distribution pipeline. The DIMP plan is not required to include the customer-owned pipeline (unless required otherwise by State law). The operator having responsibility for operations and maintenance activities for the facility is responsible for developing and implementing the DIMP plan.

Last Revision: 8/2/10

C.3.8 What do operators need to have implemented by August 2, 2011?

By August 2, 2011, operators of gas distribution systems (other than a master meter or small LPG operator) must have developed and implemented an integrity management program that includes a written integrity management plan. The plan must include the operator's procedures used to develop the seven elements listed in § 192.1007(a)-(g) At a minimum, an operator must have taken the following actions:

1. Developed and demonstrated an understanding of their system;
2. Identified and considered threats to each gas distribution facility;
3. Completed a risk evaluation and ranking of their distribution system;
4. Developed criteria for deciding when risks require measures to reduce them;
5. Determined the measures to reduce risk;
6. Begun implementing the measures to reduce risk or have a plan to implement measures to reduce risk which includes an implementation schedule;
7. Assessed the effectiveness of their leak management program and taken steps, if necessary, to correct deficiencies;
8. Established a baseline measurement for each performance measure required by 192.1007(e)(1)(i)-(v);
9. Developed performance measures to evaluate the effectiveness of measures to reduce risk, have a plan to collect the performance measure data, and begun collecting data to establish a baseline measurement;
10. Determined the appropriate period for conducting DIMP program evaluations;
11. Reported performance measures required by 192.1007(g) for calendar year 2010;
12. Collected data as needed for mechanical fitting failures resulting in hazardous leaks beginning January 1, 2011; and
13. Identified records requiring retention and have maintained them.

Last Revision: 3/10/11

C.4 §192.1007 What are the required elements of an integrity management plan?

C.4.1 What does PHMSA see as the most critical elements of the regulation?

All of the elements are critical. The plan must have written procedures for developing and implementing all the elements.

Last Revision: 8/2/10

C.4.a Knowledge

C.4.a.1 The rule requires that an operator know its system. Must an operator excavate simply to gather information about parts of its system where it may not now have complete knowledge?

No. Operators need to gather the information that they have reasonably available to develop an understanding of their pipeline systems. The data may currently reside in different locations or be the responsibility of different groups within the company. Part of this development includes identifying information that is not now known, but which is needed to develop an understanding of the characteristics of the pipeline and necessary to assess applicable threats and to analyze its risk.

Last Revision: 8/2/10

C.4.a.2 There are some characteristics about an operator's system that may not be known during the development of the IM plan. What are PHMSA's expectations for filling those voids?

Operators need to use opportunities that arise, such as the pipeline being excavated for operation, maintenance, or other reasons, to collect additional information needed to better understand their pipeline system. Operators are required to incorporate into their plan and implement procedures to gather this information when the opportunity exists. This information may or may not prompt a reevaluation of the plan, but at a minimum, will be considered for analysis during the next scheduled evaluation. Records need to be maintained and updated to reflect changes to the system. Over time, PHMSA expects that an operator's understanding of its pipeline system and the quality of their risk analyses will improve.

If an operator's records have been destroyed or are no longer available, the operator must collect sufficient information, perform appropriate tests, and create records or maps for the safer operation, maintenance, and emergency response of the system.

Last Revision: 8/2/10

C.4.a.3 Who qualifies as a "subject matter expert"?

Subject matter experts are simply people who have specific knowledge of topics and/or facilities under consideration. This includes the operator's operations and maintenance personnel – the people who construct, inspect, maintain and oversee its distribution facilities day-to-day. For some operators, this may include contractor personnel that have performed construction or operation and maintenance activities for a long period of time or for unique and/or special circumstances. In some instances, an operator may want to involve subject matter experts beyond its employees. For example, if analysis shows that an operator is having difficulty minimizing the detrimental effects of stray currents, the operator may want to involve in its program an outside person with expertise or specialized knowledge in this area.

Last Revision: 8/2/10

C.4.a.4 What data will be required to be collected for new gas pipelines going in the ground?

The DIMP regulation prescribes two minimum data elements that must be captured and retained on any new distribution pipelines: the location where the new pipeline is installed and the material of which it is constructed. Pipeline, defined in §192.3, means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Additionally, operators must collect data about new gas pipelines which will be needed to assess current and future threats and risks to the pipeline's integrity. This includes information about the characteristics of the pipeline's design, operations, and the environmental factors where the pipeline is installed.

In addition, an operator must also consider the data it needs to comply with the various record keeping requirements in Part 192 such as those for pipeline design, testing, construction, corrosion control, customer notification, uprating, surveying, patrolling, monitoring, inspection, operation, maintenance, emergencies, and operator qualification. The GPTC Guide, Appendix G-192-17, provides operators with guidance on explicit requirements for reports, inspections, tests, written procedures, records and similar actions. States may have additional requirements.

Last Revision: 8/2/10

C.4.a.5 What comprises "reasonably available" information?

PHMSA does not intend that operators expend excessive effort, review every record available in their archives, or explore every nuance about their pipelines. At the same time, PHMSA expects that operators will devote sufficient effort to develop as thorough an understanding of their pipelines as they can while using reasonable effort.

The availability of records will vary among operators. Some operators may retain records for many years and others only for the length of time required by Part 192. Some data is stored electronically and some is paper based. Additionally, some records are stored on-site and other records may be stored off-site, such as at regional offices or long term storage facilities. Any record which the operator can access is reasonably available. All records required by Parts 191 and 192 are reasonably available. Operators need to review all records that are relevant to the current condition of the pipe or have a significant impact on the integrity of the pipe. For example, a steel pipe may have been brought under adequate cathodic protection five years ago but was not under cathodic protection in prior years. Any records showing that the pipe was not under cathodic protection, is relevant to the current condition of the pipe.

Operators must identify additional information that is needed to fill gaps due to missing, inaccurate, or incomplete records and develop a plan to collect it. They may collect this information through their normal activities including those that go beyond those activities specified in Part 192. For example, missing facility location, material and condition data can be gained when the pipe is located and/or exposed.

Operators could involve maintenance personnel in their information collection activities, surveying them about unusual circumstances they have encountered in their activities and/or asking them to review resulting system descriptions and identify any information they believe is useful that is not already included.

Last Revision: 3/10/11

C.4.a.6 Must an operator's plan include the sources used to demonstrate an understanding of its gas distribution system?

An operator needs to be able to demonstrate to regulators that they have an understanding of their gas distribution system developed using sources of information that are "reasonably available". The plan should identify the information sources. Examples of sources that are reasonably available include documents, records, field notes, maps, historical procedures and design standards, bill of materials, procurement records and specifications, and information obtained from subject matter experts. These sources are used to identify the characteristics of the pipeline's design, operations and environmental factors that are necessary to assess the applicable threats and risks to the distribution system. Operators also need to consider information gained from past design, operations, and maintenance. In order to verify that an operator has met this requirement, the inspector may ask the operator for information about the sources such as: the name of the documents, the time period covered by the documents, the document's location and format (e.g. electronic, paper, or subject matter expert interview, etc.), the forms used to collect data, the fields on the forms, the instructions used to complete the forms, and a history of how this information collection changed over time.

Last Revision: 3/10/11

C.4.b Identify Threats

C.4.b.1 Must an operator use a computer-based risk analysis model?

No. Risk analysis is a process of understanding what factors affect the risk posed by a pipeline system and which are most important. For a complex system, use of a computer-based risk model may make this process easier, but the use of a computer based modeling system is not required. For a simple distribution pipeline system, it is possible to do a credible analysis that leads to an understanding of factors/areas that are important to risk without use of such a model. The GPTC guidelines include suggestions for simpler approaches.

Last Revision: 8/2/10

C.4.b.2 Must each of the 8 threats be considered for every pipeline type?

Yes, an operator's DIMP plan must consider each of the 8 threats for the pipeline system. The eight threats categories are corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. Some threats may not be relevant to all pipe types or all operators' circumstances. Some threats may apply but are not obvious. For example, corrosion is not a threat to plastic facilities but could be a threat to tracer wires, transition fittings, or to short pieces of metal main or services in a plastic system. Material or weld failures could apply to plastic (the brittle failure issue and potential for faulty fusion joints, for instance). Excavation damage occurs regardless of the pipe material.

Last Revision: 2/9/11

C.4.b.3 The DIMP requirements include knowing the condition of facilities that are at risk for potential damage from external sources. Cross bores of gas lines in sewers have been reported at 2-3 per mile in high risk areas – predominately where trenchless installation methods were used for gas line installs and where sewers and gas lines are in the proximity of each other. Does the potential for cross bore of sewers resulting in gas lines intersecting with sewers need to be determined?

Yes, the threat of excavation damage includes consideration of potential or existing cross bore of sewers which have resulted in gas lines intersecting with sewers. Pursuant to § 192.1007(a)(2), the operator must consider information gained from past design, operations, and maintenance. If operators used trenchless technologies without taking measures to locate sewer laterals and other unmarked facilities during construction, there may be a risk that their facilities were installed through the foreign facility. If this excavation damage threat applies to the operator, they must evaluate its risk to their system. Depending on the results of the risk evaluation, they may need to identify and implement measures to reduce this risk to existing and future facilities.

Last Revision: 3/10/11

C.4.c Evaluate and Rank Risks

C.4.c.1 What are the key things an operator should be focusing on when developing an effective risk assessment methodology?

High-quality data is core to an effective risk assessment. The integrity management plan must contain procedures for how the operator evaluates and ranks risks. Operators need to have a plan to identify and define the data necessary for the analyses. Additionally, processes should be in place to provide for data accuracy, completeness, and consistency. They should have a procedure to validate data and improve future data collected.

Operators must consider the risks (likelihood as well as the consequences of a failure) that might result from each threat. A potential incident of relatively low likelihood which produces significant consequences may be a higher risk than an incident with somewhat greater likelihood which may not produce major consequences.

Last Revision: 8/2/10

C.4.c.2 From which date are operators required to collect data for their plan?

Operators should use the information they already have and start keeping additional data to develop their plan (e.g., assess the threats) as soon as possible. They need to assemble and evaluate enough data to be able to evaluate the risk. Useful and usable historical data is needed to identify threats and trends.

Last Revision: 8/2/10

C.4.d Identify and Implement Measures to Address Risks

C.4.d.1 Must an operator implement additional or accelerated actions to reduce risk from its pipeline?

The DIMP rule is intended to improve safety performance. Improving performance may require operators to implement additional or accelerated actions to manage identified system risks, but in other instances such actions may not be required. Some operators have already implemented additional risk control and mitigation activities voluntarily. It is possible that these ongoing actions already adequately address the risks that are significant to some pipeline systems.

What the DIMP Rule does require is for operators to periodically consider potential improvements to their IM program. Operators must perform a risk analysis to understand the factors that are important to their risk and should compare the results of this analysis to the actions now being taken to assure pipeline safety. If gaps are identified (i.e., instances in which some factor important to risk is not now being adequately addressed) then appropriate risk control practices may need to be implemented. Operators also may find it appropriate to reduce some non-mandated actions now being taken (e.g., which address risks of lower importance) and to reallocate those resources to address higher priority risks. Operators must still comply with all the requirements of the regulations.

Last Revision: 8/2/10

C.4.d.2 How will small operators, with limited staff, be able to implement the requirements for risk analysis and selection of risk control measures?

The level of analysis required and risk control measures to be implemented are related to the complexity of an operator's distribution pipeline system and the variability of threats across a system. Operators with small staffs typically operate smaller, simpler systems, so that the effort required to conduct risk analysis and to select risk control measures should be less than that required of operators of more-complex systems.

PHMSA published, "*Guidance on Carrying Out Requirements in the Gas Distribution Integrity Management Rule Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines,*" to help large and small, master meter, and LPG operators implement the requirements of subpart P of Part 192. Guidance for large and small operators begins at section I and for master meter and LPG operators at section V of this document. The document is located on the PHMSA's DIMP web site under DIMP Key Documents http://primis.phmsa.dot.gov/dimp/documents.htm.

The Gas Piping Technology Committee (GPTC) DIMP guidelines provide guidance on relatively-simple approaches to risk analysis. The American Public Gas Association (APGA) Security and Integrity Foundation, with partial funding from PHMSA, developed the Simple, Handy, Risk-Based, Integrity Management Plan (SHRIMP), a computer-based program that is intended to assist small operators in preparing a plan to meet rule requirements.

Last Revision: 8/2/10

C.4.d.3 If an operator already has a leak management program, does the operator have to implement a new program in response to this regulation?

Not necessarily. Operators may not need to implement new leak management programs. Rather, operators should review their current leak management program to assure that it is effective and when needed, adjust their program to comply with the regulation. Leak management is an important factor in managing the risks associated with distribution pipeline systems. PHMSA recognizes that distribution pipeline operators currently have leak management programs in place and that these programs are generally effective. For example, corrosion is a leading cause of distribution pipeline leaks, but corrosion is only the cause of four percent of reportable distribution incidents; PHMSA believes that effective leak management is a major reason for this performance – operators identify and address severe leaks before incidents occur.

Last Revision: 8/2/10

C.4.d.4 Why not simply require operators of gas distribution pipelines to replace old pipe?

The rule requires that operators analyze their pipeline systems to identify the hazards that affect them and evaluate the risks posed by each threat. Operators must determine and implement measures designed to reduce the risks from failure. Pipe replacement is certainly one action an operator could take to mitigate some risks to its system.

Simply because a pipeline is old, does not mean that it is a risk to public safety. Some types of older pipe operate safely and have not been involved in incidents. Meanwhile, some newer pipes, including particular kinds of plastic fittings, have proven problematic and have caused incidents. State regulators have occasionally required operators to implement pipe replacement programs, but these replacement programs have been targeted to specific problematic pipe based on the local circumstances facing particular operators. Operators already are required to initiate programs to recondition or phase out segments of pipelines determined to be in unsatisfactory condition. Threats such as excavation damage, which is the leading cause of distribution pipeline incidents, would not be addressed by a pipe replacement program. The rule requires gas operators to analyze the risk of their pipeline, given their unique circumstances, including the age of their pipeline system. Operators should use these risk analyses to identify actions to reduce risk, including the possibility of replacing selected pipe. Regulators may oversee an operator's risk management decisions.

Last Revision: 8/2/10

C.4.d.5 What kind of issues should an operator focus on in addressing the threat of Excavation Damage as part of its DIMP Plan?

Excavation damage is the leading cause of "significant" pipeline incidents (causing injury or fatality). PHMSA published a document entitled, *Damage Prevention Assistance Program (DPAP): Strengthening State Damage Prevention Programs*. Building on the nine elements of effective damage prevention programs found in the *Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES)*, this document provides guidance to stakeholders for strengthening state damage prevention programs. While not all of these nine elements are within the operator's direct control, certain operators working with state regulators and other stakeholder groups have found ways to facilitate progress in addressing the nine elements.

Last Revision: 8/2/10

C.4.d. 6 In order to eliminate the need for a leak management program, how quickly would an operator need to repair all leaks?

The rule states that a leak management program is not needed if all leaks are repaired when found. All hazardous leaks must be repaired promptly. To eliminate the need for a leak management program, an operator would need to continue to work on each leak, hazardous and non hazardous, until it is eliminated as opposed to scheduling the repair or periodically monitoring the leak.

Last Revision: 8/2/10

C.4.d.7 Can the installation of excess flow valves be a method to mitigate risks?

Excess flow valves are one means to reduce the consequences of a potential incident when properly designed and installed. The valve automatically shuts off the flow of gas in a service line when the gas flow in the line exceeds the valve setting. The valve trips when there is severe damage to the pipeline, significantly increasing the gas flow rate. Such significant increases in gas flow rate are most often caused by excavation damage that ruptures the service line downstream of the valve. The risk of the excavation damage still exists. EFVs are an efficient means of reducing the consequences in densely populated areas, on services to public or difficult to evacuate buildings, or areas where operators cannot reach rapidly shut off the flow of gas in an emergency. The GPTC DIMP Guidance identifies the use of an EFV as a possible risk mitigation measure.

Last Revision: 8/2/10

C.4.e Measure Performance, Monitor Results, and Evaluate Effectiveness

C.4.e.1 Why has PHMSA selected the performance measures that it has for periodic reporting?

Measuring performance periodically allows operators to determine whether actions being taken to address threats are effective, or whether different actions are needed. It is also important for PHMSA and the States to measure the safety improvement (i.e., performance) achieved by this new regulation. Ultimately, a decrease in the number and consequences of distribution pipeline incidents will be the true measure of success, but it will take many years of accumulating data to determine with confidence that there is a declining trend in incidents/consequences. PHMSA needs data that will be useful in a shorter time frame to show whether improvements are being realized or if further adjustments to requirements are needed.

PHMSA has concluded it would be most useful for operators to report four performance measures. PHMSA recognizes that there will be some variability in the criteria for these performance measures among operators. The performance measures are intended to measure individual operator, state, and national trends.

The total number of leaks eliminated or repaired by cause and the number of hazardous leaks eliminated or repaired by cause are two of the reportable performance measures. Leaks can lead to incidents and hazardous leaks represent the highest risk leaks. PHMSA and State partners expect effective integrity management programs to produce a reduction in the number of leaks. The total number of leaks scheduled for repair has historically been part of the Annual Report submitted by operators of distribution pipelines.

The other reportable performance measures are the number of excavation damages and the number of excavation tickets. Excavation damage is the leading cause of significant distribution pipeline incidents. The number of excavation tickets is an indicator of the total amount of excavation activity in an area. This data will be used to normalize the reported number of excavation damages in analyzing performance since excavation damages occur as an unintended consequence of digging. PHMSA and State partners would expect effective integrity management programs to produce a positive trend in the level of excavation damage per the number of damages per ticket (or per 1000 tickets) over time.

Last Revision: 8/2/10

C.4.f Periodically Evaluation and Improvement

C.4.f.1 How often does an operator need to evaluate its program?

Operators must evaluate their program at a period appropriate for their system, but at an interval not exceeding five years. An operator should re-evaluate its IM program whenever new knowledge, new threats or other information would substantially alter the operator's DIMP program. This could range from once each calendar year to less frequently, but must not exceed once every five years.

Last Revision: 8/2/10

C.4.g Report Results

Performance Measures

C.4.g.1 When must operators start collecting and maintaining records with data needed for performance measures?

Reportable performance measures are to be submitted via the Gas Distribution Annual Report for Calendar Year 2010 which covers activities from January 1, 2010 thru December 31, 2010. The 2010 calendar year Annual Report is due by March 15, 2011.

Last Revision: 2/9/11

C.4.g.2 When are performance measures due on Annual Reports?

The reportable performance measures are to be submitted via the 2010 Gas Distribution Annual Report form which is due by March 15, 2011. An operator also must report this information to the state pipeline safety authority if a state exercises jurisdiction over the operator's pipeline.

Mar. 15, 2011 – Operators use proposed revised Gas Distribution Annual Report form, PHMSA F 7100.1-1 (12-05). It contains fields for reportable performance measures for the 2010 calendar year. Mechanical fitting failures are not to be reported for calendar year 2010.

Mar. 15, 2012 - Annual Report for calendar year 2011 must contain the required data for reportable performance measures from January 1, 2011 thru December 31, 2011.

Last Revision: 2/9/11

C.4.g.3 Can PHMSA further define the number of excavation tickets on the new form?

The definition of an "excavation ticket" varies among state one-call programs. Requiring operators to track tickets in two ways— one matching their one-call program definition and one matching a common national definition, would entail considerable additional effort without commensurate benefit. PHMSA encourages operators to use the criteria currently in place with the State law and one-call center which determines when notifications should be made.

The total number of excavation tickets includes all receipts of information by the underground facility operator from the notification center. Operators may choose to include or not include receipts of information directly from excavators or others. An operator's reporting criteria should remain consistent from year to year.

Last Revision: 8/2/10

C.4.g.4 For municipal operators or joint utility operators, should the number of excavation tickets include all excavation tickets or just those sent to the gas department?

The number of excavation tickets should only include a count of the receipts of information from the notification center to the gas pipeline underground facility operator.

Last Revision: 8/2/10

C.4.g.5 Are multiple tickets for a single job counted as a single excavation ticket?

Some state laws require excavators to call in additional requests for on-going jobs prior to the life of the first excavation request expiring. In reporting data these additional requests for excavation projects of extended duration may be counted since there is excavation work associated with those requests. However, operators do not need to change the criteria for counting excavation tickets for the purpose of reporting performance measures. If they currently count multiple tickets for a single job, they may continue that practice. The definition of "ticket" should remain consistent with State law and one-call center definition.

Last Revision: 8/2/10

C.4.g.6 What if the excavation damage occurs on an excavation with no ticket?

The occurrence must be reported in the number of excavation damages but not counted as an excavation ticket. The lack of a ticket likely means that damage prevention activities associated with one-call programs did not occur and that damage may thus have been more likely.

Last Revision: 8/2/10

C.5 §192.1009 What must an operator report when a mechanical fitting fails?

C.5.1 Why is PHMSA collecting data about mechanical fitting failures?

PHMSA has seen some regional issues with mechanical fittings. PHMSA plans to analyze the national data from the Annual Reports to develop better information about the types and causes of fitting failures. This information will be communicated to operators so that they can act appropriately.

Last Revision: 8/2/10

C.5.2 Do States already collect the type of information that is to be collected for mechanical fitting failures?

Not fully. Mechanical fitting failure information has been collected in Annual Reports and Incident Reports as a subset of the "material and weld", "equipment", and "other" failure sections. The information collected on the reportable incident form was limited to the type of joint and the cause of the failure, either construction or material defect and was only reported if the mechanical fitting failure resulted in a reportable incident. On the Annual Report, the mechanical fitting failures would be included in the count of "Leaks Eliminated/Repaired During Year", categorized by threat. The information now being collected for mechanical fitting failures is more detailed but excludes instances that result in non-hazardous leaks. The incident report was updated on January 31, 2010. For a copy of the report, go to PHMSA's web site at http://www.phmsa.dot.gov/pipeline/library/forms .

Last Revision: 8/2/10

C.5.3 Should both steel and plastic mechanical fitting failures be reported? How about the different styles of plastic mechanical fittings?

All types of mechanical fitting failures should be included regardless of material. The objective of the data collection is to identify mechanical fittings which, based on a historical data, are susceptible to failure. The Advisory Bulletin ADB-86-02 and the update to it, ADB-08-02, identified issues with mechanical fittings which could lead to failure. The bulletin advised operators to perform certain actions. Determining the root cause of these mechanical fitting failures is important to determine if and what type of additional actions may be needed if trends are identified. PHMSA intends for operators to report all types and all sizes of mechanical fitting failures which result in a hazardous leak. The failure can occur on a fitting connected to a pipe or a fitting that joins sections of pipe. Mechanical fittings include stab, nut follower, and bolt type fittings. The reporting requirements apply to failures in the bodies of mechanical fitting or failures in the joints between the fittings and pipe.

Operators are to report mechanical fitting failures as the result of any cause including excavation damage. Mechanical fittings are to be included regardless of the material they join. Include mechanical fittings which join steel to steel, steel to plastic, and plastic to plastic. Examples of the use of mechanical fittings may be found in the following applications: service tees, tapping tees, transition fittings, couplings, risers, sleeves, ells, "Ys", and tees. Failures on fittings that are joined by solvent cement, adhesive, heat fusion, or welding are not to be reported as mechanical fitting failures.

Last Revision: 8/2/10

C.5.4 Since there is a new form for mechanical fitting failures which result in a hazardous leak, do these failures still need to be reported under Part C of the Annual Report?

Yes, operators need to include all mechanical fitting failures which result in hazardous leaks eliminated or repaired as part of the total leaks reported on the Annual Report in Part C - TOTAL LEAKS AND

HAZARDOUS LEAKS ELIMINATED/REPAIRED DURING YEAR. Additionally, they must report detailed information about each mechanical fitting failure which results in a hazardous leak on a separate Gas Distribution Mechanical Fitting Failure Form (PHMSA F–7100.1–2).

PHMSA created the new Mechanical Fitting Failure Report form [PHMSA F 7100.1-2] to address the new annual reporting requirement established by DIMP for hazardous leaks on mechanical fittings. Operators may submit data at anytime and at any frequency throughout the year (preferred), or they may submit all mechanical fitting failure reports in one submission. Regardless of the method they select, the reports must be submitted by March 15, 2012 for failures which occurred in calendar year 2011. If an operator does not experience any mechanical fitting failure which results in hazardous leaks, they do not need to submit a Mechanical Fitting Failure Report form. The online system for the new Mechanical Fitting Failure Report form [PHMSA F 7100.1-2] is now in operation.

NOTE: Online submission via PHMSA Portal is required unless an alternative reporting method is granted by PHMSA. More information is available at PHMSA's, Office of Pipeline Safety web site, Pipeline Safety Community, located at http://www.phmsa.dot.gov/pipeline and click the "Online Data Entry" hyperlink listed in the first column.

Last Revision: 3/10/11

C.6 §192.1011 What records must an operator keep?

C.7 §192.1013 When may an operator deviate from required periodic inspections of this part?

C.7.1 How can operators use their DIMP programs to justify reductions in other periodic test and inspection requirements?

Part 192 includes requirements to perform certain tests and inspections periodically. For example, leak surveys must be conducted annually in business districts and atmospheric corrosion surveys must be conducted every three years on exposed pipe. These activities are intended to address a potential threat to distribution pipeline integrity. As operators complete risk analyses and implement measures directed at addressing threats of particular importance to their pipeline systems, the relative value of these required periodic activities could be shown to decrease in specific areas.

The rule includes a provision which allows operators to submit proposed adjustments to the frequency of periodic actions now required in Part 192, based on the results of their risk assessment in their integrity management programs and engineering analysis. Proposed changes will be reviewed by the regulatory authority exercising oversight of the operator and can be approved if the authority agrees that the proposed changes provide an equal or improved overall level of safety. This provision is intended to allow operators to shift resources from generically-required periodic risk control activities to activities that are more specifically focused on the issues of importance to their particular pipeline systems. The proposal must provide an equal or greater overall level of safety.

Last Revision: 8/2/10

C.7.2 What will PHMSA (or States) require for proposals for alternate inspection intervals?

Proposals must be submitted to each applicable oversight agency (usually the State). Each State will implement this provision under the State's procedures. State authorities and regulatory structures differ. Requirements for consideration of an alternative interval may differ among State regulatory authorities. The regulatory authority will be responsible for reviewing each proposal, determining safe intervals based on the information in the operator's proposal, and approving or rejecting the proposal.

Proposed alternative inspection intervals must demonstrate an equal or improved overall level of safety including the effect of the reduced frequency of periodic inspections. A quantitative estimate of risk is not required. PHMSA is developing criteria for evaluating an operator's alternative interval proposal in the states where PHMSA exercises enforcement authority over distribution pipelines.

Last Revision: 8/2/10

C.8 §192.1015 What must a master meter or small liquefied petroleum gas (LPG) operator do to implement this subpart? *(Answers from §192.1007 apply to this section unless otherwise noted).*

General

C.8.1Are all LPG operators and natural gas operators, regardless of the size of their distribution system, subject to the DIMP regulation?

The distribution integrity management regulation applies LPG and natural gas operators of all sizes except as provided in 192.1(b).

The requirements under DIMP are the same for master meter operators and small LPG operators. Section 192.1015 is specific to these operators. A master meter operator means a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter or by other means, such as by rents. LPG operators serving fewer than 100 customers from a single source are considered small LPG operators. PHMSA used the criterion from section 191.11 which excludes LPG operators serving fewer than 100 customers from a single source from the requirement to file an Annual Report.

LPG operators serving 100 or more customers from a single source must meet the same requirements applicable to all natural gas operators. Section 192.1007 is specific to these operators.

Last Revision: 8/2/10

C.8.2 Why are master meter and small LPG operators subject to different requirements?

The requirements for these smaller operators recognize the less complicated nature of their facilities. Master meter and small LPG systems are generally small and cover limited geographic areas. These operators often have more direct control over excavation in the area in which they operate, providing more positive control over what is the greatest risk to a distribution pipeline system. The systems are also less diverse, usually involving only pipe, meters, and service regulators. There have been few significant incidents on master meter and LPG distribution systems. This justifies a reduced set of integrity management requirements.

Last Revision: 8/2/10

C.8.3 What do master meter and small LPG operators need to have implemented by August 2, 2011?

By August 2, 2011, master meter operators and small LPG operators must have developed and implemented a written integrity management program that includes a written integrity management plan. The plan must include the operator's procedures used to develop the elements listed in §192.1015(b)-(c). At a minimum, these operators must have taken the following actions:

1. Developed and demonstrated an understanding of their system;
2. Identified and considered threats to each gas distribution facility;

3. Completed a relative risk ranking of each identified threat to the distribution system;
4. Developed criteria for deciding when risks require measures to reduce them;
5. Determined the measures to reduce risk;
6. Begun implementing the measures to reduce risk or have a plan to implement measures to reduce risk which includes an implementation schedule;
7. Are monitoring the number of leaks eliminated or repaired on its pipeline and their causes.
8. Determined the appropriate period for conducting DIMP program evaluations; and
9. Identified records requiring retention and have maintained them.

Last Revision: 3/10/11

Elements

C.8.a Knowledge

C.8.b Identify Threats

C.8.c Rank Risks

C.8.d Identify and Implement Measures to Mitigate Risks

C.8.e Measure Performance, Monitor Results, and Evaluate Effectiveness

C.8.f Periodically Evaluation and Improvement

ATTACHMENT B

COMPARISONS OF MAINS & SERVICES DATA

Mains Data 2011	Liberty	NH Gas	Unitil
Unprotected Bare Steel	11.60	-	25.85
Unprotected Coated Steel	17.76	0.12	4.42
Cathodically Protected Bare Steel	0.16	-	-
Cathodically Protected Coated Steel	647.69	2.77	80.57
Plastic	534.98	14.40	380.86
Cast & Wrought Iron	120.24	11.96	8.05
Total Miles of Main	1,332.43	29.25	500
Unprotected Steel Mains	29	0	30
Cast Iron & Wrought Iron Mains	120	12	132
Problem Mains	150	12	162
Problem mains - % of Total	11.23%	41.29%	32.35%
Problem mains - per mile.	0.1123	0.4129	0.3235
Corrosion Leaks	24	3	62
Natural Forces	26	2	4
Excavation	8	-	7
Other Outside Force Damage	-	-	-
Material or Welds	-	-	1
Equipment	82	-	3
Operations	-	-	-
Other (Joint Leaks)	106	-	33
Total Main Leaks	246	5	110
Corrosion Leaks Per Mile of Unprotected Steel	0.82	26.09	2.05
Cast Iron & Wrought Iron Leaks/Mile	0.88	-	0.25
All Leaks Per All Miles of Main	0.18	0.17	0.22
% Unaccounted for Gas	1.10%	2.92%	0.74

Services Data 2011	Liberty	NH Gas	Unitil
Unprotected Bare Steel Services	6,871	-	360
Unprotected Coated Steel Services	1,824	4	127
Cathodically Protected Bare Steel Services	-	-	7
Cathodically Protected Covered Steel Services	14,415	15	148
Plastic Services	40,631	777	20,426
Cast & Wrought Iron Services	4	55	2
Cu Services and Other	1,969	-	46
Total Number of Services	65,714	851	21,116
Problem Services	10,668	59	535
Problem Services % of Total	16.23%	6.93%	2.53%
Corrosion Service Leaks	66	4	21
Natural Forces Service Leaks	2	-	-
Excavation Service Leaks	40	-	18
Other Outside Force Damage Service Leaks	3	-	-
Material or Welds Service Leaks	1	-	4
Equipment Service Leaks	46	-	6
Operations Service Leaks	-	-	-
Other Service Leaks	1	-	44
Total Service Leaks	159	4	93
Corrosion Leaks Per 1000 Unprot Steel Svcs	7.59	1,000.00	43.12
All Leaks Per 1000 Services	2.42	4.70	4.40

ATTACHMENT C

Cost Estimate 504.03 (e): Service I.D. Tags			
Item	Cost per Unit	Est Units	Total
Records Research & Program Development	$ 30.00	10	$ 300.00
Tag Development & Procurement	$ 0.75	1700	$ 1,275.00
Labor to Install (including travel)	$ 32.02	1700	$ 54,434.00
Transportation Expense	$ 0.86	1700	$ 1,462.00
Programming Asset Management	$ 500.00	1	$ 500.00
Data Entry Asset Management	$ 18.00	85	$ 1,530.00
Programming Service Line Inspection	$ 2,000.00	1	$ 2,000.00
O&M Manual Changes	$ 80.00	2	$ 160.00
		Total	$ 61,661.00

Note: The Company does not expect that the on-going inspection costs will be material if they are done in conjunction with existing service line inspection programs.

Cost Estimate 506.01 (l)(i): STAGE 1 for Multi Building				
Item	Cost per Unit	Est Units	Total	Locations
Records Research & Program Development	$ 30.00	160	$ 4,800.00	Eliminated via records research
Field Audit	$ 0.75	1700	$ 1,275.00	Required field visits
Labor to audit (including travel)	$ 256.16	106.27	$ 27,222.12	Field visits per day
Transportation Expense	$ 0.86	10000	$ 8,600.00	Audit Days
Programming Asset Management	$ 500.00	2	$ 1,000.00	
			$ -	
		Sub-Total	$ 42,897.12	

Cost Estimate 506.01 (l)(i): STAGE 2 Multi Building				
Item	Cost per Unit	Est Units	Total	
Program Development	$ 30.00	10	$ 300.00	
Tag Development & Procurement	$ 1.00	8000	$ 8,000.00	Estimated number of locations
Labor to Install (including travel)	$ 32.02	1500	$ 48,030.00	
Transportation Expense	$ 0.86	4000	$ 3,440.00	
Programming Asset Management	$ 500.00	1	$ 500.00	
Data Entry Asset Management	$ 18.00	85	$ 1,530.00	
Programming Service Line Inspection	$ 2,000.00	1	$ 2,000.00	
		Total	$ 63,800.00	

$ 106,697.12

Cost Estimate 506.01 (l)(2): Meter Tags			
Item	Cost per Unit	Est Units	Total
Records Research & Program Development	$ 30.00	10	$ 300.00
Tag Development & Procurement	$ 0.75	28000	$ 21,000.00
Labor to Install (including travel)	$ 32.02	2000	$ 64,040.00
Transportation Expense	$ 0.86	13000	$ 11,180.00
Programming Asset Management	$ 500.00	1	$ 500.00
Data Entry Asset Management	$ 18.00	85	$ 1,530.00
Programming Service Line Inspection	$ 2,000.00	1	$ 2,000.00
O&M Manual Changes	$ 80.00	2	$ 160.00
		Total	$ 100,710.00

Note: The Company does not expect that the on-going inspection costs will be material if they are done in conjunction with existing service line inspection programs.

Average Welder Multiple Qualification Test Direct Costs

	Unit's	Cost/Hr	Cost	Total Cost
Welder & Equipment	24	$89	$2,136	$2,136
Welding Consumables	1	$58	$58	$58
10 feet of 12" Pipe Sch 40	1	$962	$962	$962
Inspectional Services Quality Assurance Labs				
Test Visual overview	16	$78	$1,248	$1,248
Test Mileage	60	$1	$60	$60
Destructive Testing				
Girth Weld 8 coupons @ $150/coupon	8	$150	$1,200	$1,200
Branch Connections 4 coupons @ $150/coupon	4	$150	$600	$600
			Total	**$6,264**

PUC 506.01 (m) Telemetering		
Item	Cost	
RTU Package Cost	$	7,776.00
PLC Mixed I/O	$	662.00
Pressure Transmitters	$	4,875.00
Manifold w/ test port	$	850.00
Temp Wells	$	222.00
Temp RTD's	$	2,004.00
PDS	$	735.00
Traffic Box	$	849.00
Fiber Bases	$	256.00
Tec 8	$	3,915.00
Mercury Board	$	506.00
Labor & Trans	$	10,530.00
Supervision	$	1,975.00
Programming	$	1,000.00
Misc Materials	$	1,000.00
Total	$	37,155.00

ATTACHMENT D

Unitil Pipeline Safety Procedures - Rev. 2.0 April 27, 2012

2-N Leak Management

1.0 GENERAL

This procedure is a guide to performing an investigation of a leak indication. It is intended that this procedure be used as a general guide, and that personnel use good judgment considering all information available when responding, investigating, and classifying leaks.

(a) Any notification from an outside source (e.g. police or fire department, other utility, contractor or general public) reporting an odor, leak, explosion or fire, which may involve gas pipelines or other gas facilities, shall be considered potentially hazardous and shall be investigated promptly until proven otherwise with instrumentation. If the investigation reveals a leak, the leak should be graded and action taken in accordance with established procedures.

(b) In order to have a gas explosion, three elements are required: the right amount of a combustible gas and oxygen, and an ignition source. Eliminating any one of these elements will eliminate the possibility of an explosion.

(c) The procedure does not cover all conceivable situations and, therefore, investigating reported or suspected gas leaks requires the exercise of individual initiative and judgment based on an understanding of the problems involved.

(d) Based on (c) above, if the situation warrants, evacuate the area, prevent entry to the area by unauthorized persons, and re-route vehicular traffic. This could require the assistance of local police and fire departments.

2.0 DISCOVERY OF A LEAK INDICATION

A leak indication may be discovered in many ways, such as the following.

(a) As the result of continuing surveillance (see Procedure 2-C).

(b) As the result of a patrol or a leak survey (see Procedure 2-D).

(c) By a telephone call from a customer or the public (e.g. odor complaint)

3.0 LEAK DETECTION METHODS

The following gas leakage detection methods may be employed, as applicable, for detecting the presence of gas or leakage:

3.1 Surface Gas Detection Survey

Surface Gas Detection Survey: A continuous sampling of the atmosphere at or near ground level for buried gas facilities and adjacent to above ground gas facilities with a gas detector system capable of detecting a concentration of 50 ppm gas in air.

3.1.1 Equipment

The equipment used to perform these surveys may be portable or mobile.

(a) For buried piping, sampling of the atmosphere should, where practical, take place as close to ground surface as permitted by gas detector design, due to the potential for rapid diffusion of leaking gas to the atmosphere.

(b) In areas where the piping is under pavement, samplings should also be at curb line(s), available ground surface openings (e.g., substructures, catch basins, sewer, power, and telephone duct openings, fire and traffic signal boxes, or cracks in the pavement or sidewalk) or other interfaces where the venting of gas is likely to occur.

(c) For exposed piping, sampling should be adjacent to the piping.

3.1.2 Utilization

The mobile survey should be conducted at a speed not to exceed10 mph during normal climate conditions. During times of excessive wind, rain and/or snow, speeds less than 5 mph should be maintained. (See Figure 2-N-1, Letter from SENSIT Technologies regarding speed). Speeds should be slow enough to allow an adequate sample to be continuously obtained by placement of equipment intakes over the most logical venting locations, giving consideration to the location of gas facilities. Gas detector design or adverse conditions may limit the use of this survey method and technicians should be cognizant of these factors. Conditions that may affect the venting of sub-surface gas leaks are:

(a) *Moisture*. A high water table, tidal effects, or excessive moisture from rain may inhibit venting of the gas to atmosphere.

(b) *Frost*. Where frost is present in the soil, leak diffusion patterns may change.

(c) *Ice and Snow Cover*. Ice and snow cover may cause surface sealing, limiting the venting of gas to the atmosphere.

(d) *Wind*. High or gusting winds may alter diffusion at the surface of the ground.

(e) Underground conduit and sewer structures can provide unobstructed and interconnected (or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See Section 4.6 below.

(f) Wall-to-Wall paving or other impervious surface areas.

3.2 Sub-Surface Gas Detection Survey

Sub-Surface Gas Detection Survey: The sampling of the atmosphere with a combustible gas indicator (CGI) or other industry accepted device capable of detecting 0.5 percent gas in air at the sampling point.

3.2.1 Utilization

(a) The area to be checked is determined by existing conditions such as frost, hills, conduits, sewers, drain lines, etc. At a minimum, check the buildings on either side and three buildings directly across the street from a structure which has a concentration of gas at the foundation wall. If any of these additional building checks show that gas is present, consider evacuation in accordance with Company protocols and continue the investigation to additional adjacent buildings until no gas is found thus identifying the hazardous area. Anytime gas has migrated into multiple buildings contact Gas System Dispatch, a supervisor and consider requesting additional help from the Fire Department. Refer to Section 10.0, *Evacuation Procedure*.

(b) The survey should be conducted by performing tests with a CGI in a series of available openings or barholes adjacent to the gas facility. The location of the gas facility and its proximity to buildings and other structures should be considered in the spacing of the sample points. Sampling points should be as close as possible to the main or pipeline, and never further than 15 feet laterally from the facility. When establishing sampling points along a gas main, the distance between these points should not exceed 30 feet. When establishing sampling points for service lines the sampling point should at the mid-point of the service, or at 30 feet whichever is the lesser distance. In establishing sampling points for both mains and services there is no need for the spacing to be less than 10 feet unless unique field conditions exist.

The sampling pattern should include sample points adjacent to service taps, street intersections, and known branch connections, as well as adjacent to buried service lines and at the building walls.

(c) Underground conduit and sewer structures can provide unobstructed and interconnected (or exclusive) migration paths toward buildings. If readings are found in these structures, further investigation should follow. See Section 4.6 below.

(d) Good judgment should be used to determine when available openings (e.g., substructures, vaults, or valve boxes) are sufficient in number to provide an adequate survey. If necessary, additional sample points (barholes) should be made.

(e) Sampling points should be of sufficient depth to directly sample within the sub-surface or substructure atmosphere and not be restricted by capping obstructions such as paving, concrete, soil moisture or frost or surface sealing by ice or water.

(f) When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation.

3.3 Soap Leakage Test

Soap Leakage Test: The application of a soap-water or other foam forming solution on exposed piping to determine the existence of a leak.

(a) The exposed piping systems should be reasonably cleaned and completely coated with the solution. Leaks are indicated by the presence of soap foam or bubbles.

(b) This test method may be used for the following:

(1) Testing exposed aboveground portions of a system, such as meter set assemblies or exposed piping on bridge crossings.

(2) Testing a tie-in joint or leak repair which is not included in a pressure test.

3.4 Pressure Drop Test

Pressure Drop Test: A test to determine if an isolated segment of pipeline loses pressure due to leakage.

(a) Facilities selected for a pressure drop test should first be isolated and then tested.

(b) A pressure test conducted on facilities solely for the purpose of detecting leakage should be performed at a pressure equal to the operating pressure of the segment. A pressure test conducted for line qualification or uprating must be performed in accordance with procedures. Refer to 2-K, *Uprating*.

(c) The test medium shall conform to Company standards (e.g. air, nitrogen or other medium approved by Engineering)

(d) The test duration should be of sufficient length to detect leakage. Unless approved by engineering these testing durations shall follow the guidelines established for commissioning new gas facilities. Refer to 4-J, *Testing*.

(e) Pressure drop tests should be used only to establish the presence or absence of a leak on a specifically isolated segment of a pipeline. Normally, this type of test will not provide a leak location. Therefore, facilities on which leakage is indicated may require further evaluation by another detection method in order that the leak may be located, evaluated, and graded.

4.0 LEAK INVESTIGATION AND ACTION CRITERIA

4.1 Scope

(a) Leak investigation and leak classification provide a means for determining the location, extent, and potential hazard of migrating gas. A leak investigation should be initiated to address a report of a possible leak indication. Leak indications may include the following:

- Odor Complaints
- Reports of dead or discolored vegetation
- Positive readings from leak detection equipment
- Soap Leakage Test

(b) Leak indications may originate from the following:

- Scheduled leak surveys
- Line patrols
- Customer reports
- Reports from the general public

(c) Regardless of their origin, leak indications should be investigated promptly to identify any hazardous condition.

(d) In any leak investigation, an operator should presume that a Grade 1 or hazardous leak might exist.

(e) Only after completing the leak investigation should an operator determine an appropriate leak classification. Leak indications may be from sources other than natural gas.

(f) Follow equipment manufacturer's instructions for testing with charcoal filters.

(g) If practicable, take a sample of the gas for laboratory analysis. Follow the instructions of the laboratory when taking such a sample.

(h) All leak investigations regardless of the findings shall be properly documented according to company protocol.

4.2 General

(a) If a leak investigation is initiated by an 'inside' odor complaint, see 4.4 below.

(b) Where a leak indication appears to originate from buried piping, operator personnel should identify the extent of gas migration. If the migration pattern extends to nearby structures, the structures should be checked for the presence of combustible gases. Structures may include buildings, confined spaces, and other buried utilities. See 4.3 below.

(c) Personnel investigating a leak indication reported as either an 'inside' or 'outside' complaint should perform a visual check for the existence of other underground utilities in the area. If investigating 'outside,' see 4.3 below. Examples of other underground facilities in the area of suspected gas migration include the following:

- Customer-owned service lines (if known)
- Buried fuel lines
- Electric lines
- Telephone lines
- Television Cable
- Water or Sewer Lines

(d) Consider the potential for gas migration under fully paved areas, ground frost, or buildings.

4.3 Outside Leak Investigation

(a) If practical, contact the person who placed the call and ascertain the location and nature of the reported leak.

(b) Perform Sub-surface Gas Detection Survey. See Section 3.2.

(c) If a meter set is outside, observe its dial for unusual flow.

(d) Look for indications of construction activity, which might have caused damage to the operator's facilities. Examples are:

- Excavation
- Pavement patches
- Landscaping
- Fencing installation
- Directional drilling or boring activity
- Settling or subsidence

(e) Look for building additions that may have been constructed over natural gas service lines.

(f) Conditions permitting, look for a pattern of vegetation damage that may indicate the presence of a leak.

(g) Check available openings in the area of a leak indication. These openings may include the following:

- Valve Boxes
- Catch Basins
- Substructures
- Vaults
- Pits
- Other openings that allow access to underground atmospheres.

(h) Review the Compliance Management System (CMS) for previously identified active leaks in the area (e.g. Grade 2 or Grade 3) and/or previous leak repair activity. Active leaks and changing leak migration patterns should be evaluated when investigating leaks.

(i) Review the Company Geospatial Information System (GIS) and Compliance Management System to determine the operating pressure, pipe material(s) and other essential asset attributes useful during leak investigations.

(j) Conduct a mobile leak survey (surface gas detection survey) at a minimum of 500 feet in each direction to include all intersecting streets. This mobile survey shall be documented on the outside leak investigation form and submitted with the investigation report.

4.4 Inside Leak Investigation

4.4.1 Safety Precautions

(a) Only an intrinsically safe flashlight may be used.

(b) Smoking or carrying lighted cigarettes, cigars, or pipes is not permitted. Lighting a match or lighter (i.e., open flames) is prohibited.

(c) The doorbell shall not be used to announce your presence because it could be a source of ignition. Attempt to gain entry by knocking on the door. Immediately report 'Can't Get In' to Gas System Dispatch who will contact the appropriate Fire Dept as well as the appropriate supervisor. The supervisor should decide whether a new work order will be issued or that other pertinent action will be taken.

4.4.2 Entering the Premise

(a) Generally, a leak detection instrument shall be used to probe the atmosphere of a building before entering the building.

(b) Turn on the combustible gas indicator (CGI) in the outside gas free air, test batteries and zero instruments before entering the building to investigate the reported odor or gas leak. For further information regarding CGI, refer to Section 12.0.

(c) Enter the building, identify yourself and close the door behind you so as not to dilute the inside air.

(d) Do not turn on or turn off any electric light, switch, motor, or other appliance or equipment that could be a source of ignition. Advise occupants likewise, if practicable.

4.4.3 Determining Existing Conditions

After entry, conduct a combustible gas indicator (CGI) test at ceiling level to determine existing conditions. Follow the procedure for the given result:

(a) Positive Gas in Air CGI reading (Hazardous Leak)

(b) No Positive Gas in Air CGI Reading - Leak Exists

(c) Negative CGI reading

(a) Positive Gas in Air CGI Reading (Hazardous Leak)

If a hazardous leak exists, as defined as a positive combustible gas indicator (CGI) reading then do the following:

(1) For positive gas in air readings of 20 % LEL (1% gas in air) the first responder shall evacuate the building of all occupants. Refer to Section 10.0, *Evacuation Procedure*.

(2) As soon as the area is secure, check and monitor adjacent buildings for gas. The area to be checked is determined by existing conditions such as frost, hills, conduits, sewers, drain lines, etc. At a minimum, check the buildings on either side and three buildings directly across the street from a structure which has a concentration of gas at the foundation wall. If any of these additional building checks show that gas is present, consider evacuation in accordance with Company protocols and continue the investigation to additional adjacent buildings until no gas is found thus identifying the hazardous area. Anytime gas has migrated into multiple buildings, contact Gas System Dispatch, a supervisor and consider requesting additional help from the Fire Department.

(3) If gas is present in multiple buildings and the source cannot be readily identified and immediately repaired contact Gas System Dispatch immediately to request a supervisor, additional field personnel and to notify the local fire department.

(b) No Positive Gas in Air CGI Reading - Leak Exists

If an inside leak does exist, but there are no positive gas in air readings from the combustible gas indicator (CGI):

(1) Attempt to isolate the fitting or appliance that the leak is coming from. Red Tag any non-jurisdictional piping and appliance and ensure that the gas is off (Refer to Procedure 3-E for Red Tag procedure). If the piping, fitting or appliance cannot be isolated then the first responder shall turn the gas off by the safest and fastest method possible (e.g., curb valve, meter valve, main valve, pipe squeeze-off tool).

Note: Evacuation of a building shall be considered any time a concentration of gas exists in the open atmosphere inside the building and/or at the discretion of the first responder in the interest of public safety. If evacuation is necessary, refer to Section 10.0.

(2) Check all entrances of the gas service, water service, sewer, underground electric and all wall openings with the combustible gas indicator (CGI).

(3) If the leak is inside, attempt to locate the source and repair it. Shut off and Red Tag the gas service, meter or appliance if the leak cannot be repaired.

(4) If an outside leak is indicated by a positive gas reading, open the cellar windows to prevent a negative pressure within the cellar. Only do so if the 'gas in air' readings are in range otherwise refer to Ventilation procedure in Section 11.0. Shut off and Red Tag the service valve, meter valves, or appliance valves. Proceed to the top floor of the building and test for gas. Ventilate by opening windows, as required, and work your way back down to the first floor.

(5) Notify Gas System Dispatch of the existing conditions as soon as circumstances will permit.

(6) Check and monitor adjacent buildings for gas. The area to be checked is determined by existing conditions such as frost, hills, conduits, sewers, drain lines, etc. At a minimum, check the buildings on either side and three buildings directly across the street from a structure which has a concentration of gas at the foundation wall. If any of these additional building checks show that gas is present, consider evacuation in accordance with Company protocols and continue the investigation to additional adjacent buildings until no gas is found thus identifying the hazardous area. Anytime gas has migrated into multiple buildings contact a dispatch, a supervisor and consider requesting additional help from the fire department.

(c) Negative CGI Reading

If upon your initial entrance into the building the combustible gas indicator (CGI) reading is negative:

(1) Question the customer (if practical) as to the location of the reported odor.

(2) If the leak is not found in the reported location, continue the investigation without interruption until the leak is found and repaired or it is determined that there is no leak. After any repair, check to be sure no other leaks are present.

(3) All procedures and precautions previously outlined apply as necessary while investigating the source of the odor or gas leak.

(4) If a leak cannot be repaired, do not leave the scene or location until relieved by the supervisor. Continue checking buildings in the area at regular intervals until there is no longer any danger of an incident.

4.4.4 Other Considerations

(a) Consider that an odor may originate from some source other than natural gas, such as gasoline, cleaning fluids, or other substances. If gasoline, cleaning fluid, or other screening odors are present in a building, it shall be assumed that such odors are either flammable or toxic and consideration shall be given to turning off the gas at the service line and to venting the building completely. Smoking or carrying lighted cigarettes, cigars, or pipes is not permitted. Lighting any match or lighter (i.e., open flames) is prohibited.

(b) Consider that gas might be migrating into a building from the outside. If this is a possibility, perform a leak detection survey around the outside perimeter of the building. This should be done whether or not entry to the building was achieved. (See Section 3.2.1 above)

(c) If gas is found outside the building, other nearby buildings should be checked to determine whether there is a presence of gas inside. (See Section 3.2.1 above)

4.5 Completing the Investigation

(a) Inform the customer, if available, of pertinent actions taken.

(b) Document the arrival and departure time, combustible gas indicator test results, conditions found, actions taken and any other pertinent information necessary to complete the necessary leak investigation report and work order.

4.6 Gas Detected in Underground Vaults or Conduits

(a) Underground conduits (e.g., electric, telephone, cable) or sewer and drain structures (e.g., storm, sanitary, catch basins, vent boxes) can provide unobstructed and interconnected (or exclusive) migration paths for gas. Therefore, if readings are found in these types of structures, the responder should conduct successive checks of all interconnecting substructures until there are decreasing readings in the gas migration area and it has been determined to be non-hazardous. If a non-hazardous condition exists after the investigation has been completed, complete documentation as required. If gas is detected in 2 consecutive substructures, then the first responder shall contact the appropriate supervisor.

(b) Buildings should also be checked to determine if interconnecting conduits are entering buildings and possibly providing migration of gas to the inside of the building. The investigation may require coverage of numerous blocks and buildings to achieve proper results.

(c) To determine which substructures are 'interconnected,' the technician should perform a visual survey of available openings, noting similarly identified substructure covers.

After identifying all successive substructures with positive readings and the clear substructures at the ends, all gas facilities between the clear substructures should be considered to be within the area of migration and should be investigated.

(d) Due to prevailing air flow within conduit systems, it is not unusual for gas leaks to be closer to substructures with zero readings than those with positive readings.

(e) Ventilate all substructures. This should reduce readings in substructures that are farther from the leak source.

(f) Notify a supervisor immediately for gas readings in two consecutive interconnected subsurface structures.

4.7 Broken Main or Service Line

(a) Upon arrival, determine the nature and extent of the emergency. If a large volume of gas is escaping, see Procedure 2-T, *Emergency Actions*, Section 6.0. If a hazardous condition exists, evacuate affected buildings and clear the area where the pipeline is broken. Refer to Section 10.0, *Evacuation Procedure.*

(b) Notify Dispatch to call the local Fire Department and/or Police Department. If the Fire Department and/or Police Department are already at the scene, coordinate the evacuation with them, if such evacuation is necessary.

(c) Check all surrounding buildings for the presence of gas. (See Section 4.4.3 above)

(d) If not already dispatched, request assistance from the appropriate supervisor. Distribution shall contribute to the decision as to whether a segment of pipeline must be shut down. Distribution crews shall follow operating and maintenance procedures for repairing broken pipelines and stand by at the scene after repairs are completed until relieved.

(e) If a substantial number of customers will be affected by the leakage, or control thereof, evaluate the extent of the shutdown and identify street names and numbers. Notify Gas System Dispatch. (Refer to Procedure 2-T, *Emergency Actions*, Section 8.0)

(f) Gas will not be restored to the affected area until all gas service lines have been shut off at the gas service or curb valve. The Outage Management System which is located in the Compliance Management System (CMS) should be used during outages. (Refer to Procedure 2-T, *Emergency Actions*, Section 8.0)

(g) Upon completion of repairs, service will be restored to customers on an individual basis. If a customer is not home, the gas will be left off and notification left for the customer advising them to call for restoration of their gas service. (Refer to Procedure 2-T, *Emergency Actions*, Section 8.0)

(h) When the leak investigation is completed, notify Gas System Dispatch.

5.0 LEAK GRADING AND ACTION CRITERIA

5.1 General

The purpose of the leak grading system is to determine the degree or extent of the potential hazard resulting from gas leakage and to prescribe remedial actions. Unitil shall ensure that leak grading is made only by those individuals who possess training experience and knowledge in the field of leak classification and investigation. [ME Puc 420.6C]

5.1.1 Use of Judgment

The material in this section is presented as a guideline. The judgment of the operator personnel at the scene is of primary importance in determining the grade assigned to a leak and the action criteria to be used.

5.1.2 Establishing the Gas Migration Area

(a) When evaluating a gas leak indication, the initial step is to determine the extent of the gas migration area.

(b) When the gas migration area extends to a building wall, the investigation shall continue into the building unless public safety or identifiable urgent circumstances prohibit entry. [ME Puc 420.6C].

(c) Once public safety or identifiable urgent circumstances no longer prohibit entry, the investigation shall continue into the building if the leak has not yet been resolved using a CGI. [ME Puc 420.6C]

5.1.3 Downgrading a Leak Indication

(a) Generally, Grade 1 and 2 leaks cannot be downgraded without a physical repair being made. Under special circumstances, in Massachusetts and New Hampshire only, a request for downgrade can be submitted to the Manager, Gas Compliance, for consideration. A documented study will be conducted and, if the request is accepted, a record of this study shall be retained by the Manager, Gas Compliance. In Maine no leak shall be downgraded without a physical repair made. [ME Puc 420.6D]

(b) The objective of Unitil's leak management program is to repair and clear leaks from the distribution system. However, leaks with physical repairs can be downgraded with prior approval from the Distribution Manager. Location, pressure, material, leak history and scheduled replacement should be the determining factors utilized for evaluation and consideration.

5.1.4 Upgrading an Existing Leak

When upgrading a leak to a higher grade, the time period for the repair is the remaining time based on its original classification or the time allowed for the repair under its new grade, whichever is less.

5.1.5 Assigning Leak Grades

Leak grades shall be assigned based on an evaluation of the location and/or magnitude of a leak to establish the leak repair priority. The leak grade should be assigned based on the conditions found (gas readings) during the initial investigation and should not be assigned based on gas readings taken after ventilation, aeration or other non-repair activities that take place. These same criteria used for initial leak grading shall be applied when reevaluating leaks.

5.2 Below Ground Grade 1 Leak Indications

5.2.1 Definition (Grade 1)

A Grade 1 leak indication is one that represents an existing or probable hazard to persons or property, and requires prompt action, immediate repair, and/or continuous action until conditions are no longer hazardous.

5.2.2 Indications (Grade 1)

Following are leak indications that would be classified as Grade 1:

(a) A leak which, in the judgment of the person performing the leak evaluation at the scene, is serious enough to warrant immediate action such as:

- Strong odor of gas
- Extensive migration pattern
- Customer complaint

(b) Escaping gas that creates a serious operating problem or hazard, such as the possibility of ignition.

(c) Escaping gas that has ignited unintentionally.

(d) An indication of gas which has migrated into or under a building, or into a tunnel.

(e) A leak indication within five (5) feet of the outside wall of a building or where it is reasonable to anticipate that gas would readily migrate to an outside wall of a building.

(f) A leak indication of 70% LEL (lower explosive level) (3.5% gas in air), or greater, in an enclosed space.

(g) A leak indication of 70% LEL (3.5% gas in air), or greater, in a small substructure (other than a gas associated substructure) such as a substructure, conduit, or catch basin.

Note: If the enclosed space is located within fifty (50) feet from an outside wall of a building the most stringent leak readings must be used for the classification.

(h) A leak indication in consecutive interconnected substructures, such as substructures or catch basins.

(i) A leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

5.2.3 Action Criteria (Grade 1)

(a) Grade 1 leak indications require:

(1) Prompt action to protect life and property, and

(2) Continuous action until the condition is no longer hazardous; and

(3) A physical repair made, except as stipulated in Section 5.1.3.

(b) Prompt action, in some instances, may include one or more of the following:

(1) Implementation of the Emergency Response Plan. (See Gas Emergency Response Plan)

(2) Evacuating premises (Refer to Section 10.0)

(3) Blocking off an area

(4) Rerouting traffic

(5) Eliminating sources of ignition

(6) Venting the area by:

- Removing substructure covers,
- Bar-holing,
- Installing vent holes, or
- Other means.

(7) Stopping the flow of gas by closing valves or other means

(8) Notifying police and fire departments. In Maine, Unitil shall immediately notify the fire department of the community in which the Grade 1 leak found to exist in its pipeline system. [ME Puc 420.6D]

(9) Repairing the pipe. Refer to Section 7.0.

(10) Replacing the pipe

(c) For outside leak odors near a building where the source of the leak cannot be determined, a bar hole survey should be conducted around the perimeter of the building, adjacent to the service, and adjacent to the main in the vicinity of the building. For more information regarding Pinpointing, refer to Section 6.1.

5.3 Below Ground Grade 2, Priority 1 Leak Indications

5.3.1. Definition (Grade 2, Priority 1)

A Grade 2 Priority 1 is a leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair or removal within ten (10) working days after the necessary state, city, or town permits are obtained and the statutory notification requirements are met. (In Maine Grade 2 Priority 1 leak repairs shall be completed within 30 days of detection of any leak [ME Puc 420.6D])

5.3.2 Indications (Grade 2, Priority 1)

The following leak indications would be classified as Grade 2, Priority 1 Leak:

(a) Any reading between five (5) and fifteen (15) feet from the outside wall of a building.

(b) A sustained gas reading of greater than 70% LEL (3.5% gas in air) between fifteen (15) and thirty (30) feet from the outside wall of a building.

(c) A sustained reading of less than 70% LEL (3.5% gas in air) but greater or equal to 50% LEL (2.5% gas in air), or greater under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak.

(d) A sustained reading of 100% LEL (5% gas in air), or greater, under a street in a wall-to-wall paved area that has a significant (greater than fifty (50) linear feet) gas migration and does not qualify as a Grade 1 leak.

(e)With a sustained reading less than 70% LEL (3.5% gas in air) but greater or equal to 50% LEL (2.5% gas in air) in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard.

Note: If the enclosed space is located within fifty (50) feet from an outside wall of a building the most stringent leak readings for that specific area must be used for the classification (e.g. a leak reading within an enclosed space located within five (5) feet from a building wall will always be classified as a Grade 1 leak).

(f) With a sustained reading between 20% LEL (1% gas in air) and 70% LEL (3.5% gas in air) in a confined space.

(g) With a reading of 70% LEL (3.5% gas in air), but greater or equal to 50% LEL (2.5% gas in air), in gas associated substructures; and which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

(h) Any leak that in the judgment of gas pipeline company personnel at the scene is of sufficient magnitude to justify scheduled repair.

(i) In Maine, a reading on a pipeline operating at 30% SMYS, or greater, in a class 3 or 4 location, which does not qualify as a grade 1 leak.

5.3.3 Action Criteria (Grade 2, Priority 1)

Grade 2, Priority 1 leaks should be for scheduled repair or removal within (10) working days after the necessary state, city, or town permits are obtained and the statutory notification requirements are met. (In Maine Grade 2 Priority 1 leak repairs shall be completed within 30 days of detection of any leak [ME Puc 420.6D]

Refer to Section 7.0, *Repair of Leaks.*

5.4 Below Ground, Grade 2 Leak Indications

5.4.1 Definition (Grade 2)

Grade 2 leak indication is one that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair or removal within 6 months or prior to the end of the year, (whichever is less) based on probable future hazard.

5.4.2 Indications (Grade 2)

The following leak indications would be classified as a Grade 2 Leak:

(a) Any sustained gas reading of less than 70% LEL (3.5% gas in air) between fifteen (15) and thirty (30) feet from the outside wall of a building.

(b) A sustained reading of less than 50% LEL (2.5% gas in air) but greater or equal to 30% LEL (1.5% gas in air), or greater under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak.

(c) With a sustained reading less than 50% LEL 2.5% gas in air) but greater or equal to 30% LEL (1.5% gas in air) in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard.

(d) With a sustained reading of less than 20% LEL (1% gas in air) in a confined space and which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

(e) With a sustained reading of less than 50% LEL (2.5% gas in air) or greater, in gas associated substructures; and which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

Note: If the enclosed space is located within fifty (50) feet from an outside wall of a building the most stringent leak readings for that specific area must be used for the classification (e.g. a leak reading within an enclosed space located within five (5) feet from a building wall will always be classified as a Grade 1 leak)

(f) Any leak that in the judgment of gas pipeline company personnel at the scene is of sufficient magnitude to justify scheduled repair.

(g) A leak indication which, in the judgment of the person performing the evaluation:

(1) Would become potentially hazardous if left unrepaired until the next scheduled evaluation; or

(2) Is of sufficient magnitude to justify scheduled repair.

(h) A leak indication, which in the judgment of an appropriate field supervisor, might develop into a Class 1 leak should changes occur, such as:

(1) Frost penetration.

(2) Paving installation or repairs.

(3) Severe drying or compaction of the soil.

(4) Construction in the area.

(5) Increase in the normal operating pressure in the pipeline.

(6) The amount and migration of gas

(i) Sustained CGI barhole readings in:

(1) An area of wall-to-wall pavement, or

(2) On both sides of a street or corners of an intersection.

(j) A leak indication that leakage has spread to both sides of a driveway and/or is migrating along the driveway towards a building.

(k) A leak indication that gas in the ground is adversely affecting the growth of trees, shrubs, or significant portions of lawn.

5.4.3 Action Criteria (Grade 2)

(a) *Deadlines*. In Massachusetts and Maine, Grade 2 leaks should be repaired, removed, or cleared within six months or before the end of the calendar year, whichever comes first. [ME Puc 420.6D]

In New Hampshire, Grade 2 leaks shall be repaired, removed, or cleared within 6 months or before the end of the calendar year from the date the leak was classified. [NH Puc 505.04]

Refer to Section 7.0, *Repair of Leaks* .

(b) *Priority*. In determining the repair priority, the following criteria may be considered:

(1) Amount and migration of gas.

(2) Proximity of gas to buildings and subsurface structures.

(3) Extent of pavement.

(4) Soil type, and soil conditions, such as frost cap, moisture, and natural venting.

(c) *Frozen Ground or Adverse Soil Conditions.* A Grade 2 leak which, under frozen or other adverse soil conditions, would readily migrate to the outside wall of a building should be repaired or removed prior to the ground freezing or prior to the occurrence of other adverse soil conditions.

(d) *Re-evaluation.* Active Grade 2 leaks shall be monitored and re-evaluated at a minimum interval of every (30) days until the leak is repaired. More frequent monitoring and evaluation may be warranted by the location and magnitude of the leakage condition. See Section 7.2 for more information regarding Leak Repair Follow-up.

(e) *Variation*. Grade 2 leaks vary greatly in degree of potential hazard, which affects scheduling for their repair or elimination. When the leak is discovered, pertinent conditions at the location of a leak shall be brought to the attention of the individual responsible for scheduling the repair. Many Grade 2 leaks, because of their location and magnitude, can be scheduled for routine repair with consideration for periodic reevaluation, as necessary.

5.5 Below Ground Grade 3 Leak Indications

5.5.1 Definition (Grade 3)

A Grade 3 leak indication is one that is non-hazardous at the time of detection, and can be reasonably expected to remain non-hazardous.

5.5.2 Indications (Grade 3)

The following leak indications would be classified as a Grade 3 Leak:

(a) A leak indication of less than 70% LEL (3.5% gas in air) in small gas associated substructures, such as gas valve boxes.

(b) A leak indication under a street in an area without wall-to-wall paving where it is it is unlikely the gas could migrate to the outside wall of a building.

(c) A leak indication of less than 20% LEL (1% gas in air) in a confined space.

5.5.3 Action Criteria (Grade 3)

In New Hampshire and Massachusetts, Grade 3 leak indications should be reevaluated during the next scheduled survey, or within 12 months of the date reported, whichever occurs first, until the leak is re-graded, repaired, or otherwise no longer results in a reading.

In Maine Grade 3 leak indications shall be surveyed and re-evaluated at least once every 180 days from the date of discovery, until the leak is repaired. [ME Puc 420.6D]

In Maine, a Grade 3 leak shall be repaired within 24 months of its detection, unless the leak is located within an approved main replacement program area in which case the time for repair may be extended to the scheduled replacement. [ME Puc 420.6D]

Refer to Section 7.0, *Repair of Leaks*.

5.6 Above Ground Leaks

(a) A hazardous above ground leak is an unintentional escape of gas from above ground piping or related gas facilities that require immediate make-safe action, because:

(1) On outside piping it can be seen, heard or felt (e.g. causes the blowing off of leak detection soap); and is in a location that may endanger the general public or property (e.g. requires an immediate evacuation to protect public safety).

(2) On inside piping it can be seen, heard or felt (e.g. causes the blowing - off of leak detection soap) and/or has sustained positive gas readings as indicated by a CGI.

(b) An above ground leak is reportable when it is hazardous based on the criteria defined above and the source of the leak is identified as jurisdictional piping. Documentation for hazardous above ground leaks should follow the same protocol as below ground leaks.

(c) Minor escapes of gas (non-hazardous releases) at threads on sound piping or at fittings that are detectable only with instruments in direct proximity or that give only slight indications with leak soap are not reportable leaks if they could be eliminated by lubrication, adjustment or tightening, even if the repair methodology is the reconstruction or replacement of parts. These leaks will be categorized as 'Fit Leaks' and documented as such.

6.0 ACTIONS PRIOR TO REPAIR

6.1 Pinpointing

Pinpointing is the process of tracing a detected gas leak to its source. It should follow an orderly systematic process that uses the following procedures to minimize excavation.

(a) The migration of gas should be determined by establishing the outer boundaries of the indications.

(b) In an urban environment, sampling is recommended at available openings (e.g., substructures, valve boxes) in the area. Testing such structures provides advantages in determining migration when pinpointing a leak, such as the following:

(1) Identifying the spread through efficient use of existing structures, thus minimizing barholes.

(2) Reducing the risk of damaging other utilities during the investigation.

(3) Expediting the investigation

(c) Foreign facilities in the area of search should be identified. The responder should look for evidence of recent construction activities that could have contributed to the leakage. Gas may also migrate and vent along a trench or bore hole provided for other facilities. Leaks could occur at the intersection of the foreign facility and the gas pipeline.

(d) Evenly spaced bar or test holes should be used over the gas line suspected to be leaking. All barholes should be of equal depth and diameter (and down to the pipe depth where necessary) and all CGI readings should be taken at an equal depth in order to obtain consistent and worthwhile readings. Using only the highest sustained readings, the gas can be traced to its source by identifying the test holes with the highest readings.

(e) Frequently, high readings are found in more than one barhole and additional techniques are necessary to determine which reading is closest to the probable source. Many of the barhole readings will normally decline over a period of time but it may be desirable to dissipate excess gas from the underground locations to hasten this process. Evaluation methods should be used with caution to avoid distorting the venting patterns.

(f) Once underground leakage has been identified, additional holes and deeper holes should be probed to more closely bracket the area. For example, test holes may be spaced six feet apart initially and then the six foot spacing between the two highest test holes might be probed with additional test holes, with spacing as close as twelve inches.

(g) Additional tests include taking CGI readings at the top of a barhole or using manometer or soap forming solution to determine which barhole has the greatest positive flow. Other indications are dust particles blowing from the barholes, the sound of gas coming from the barhole or the feel of gas flow on a sensitive skin surface. On occasion, sunlight diffraction can be observed as the gas vents to the atmosphere.

(h) When gas is found in an underground conduit, testing at available openings may be used to isolate the source in addition to the techniques previously mentioned. Many times the leak is found at the intersection of the foreign conduit and a gas line.

(i) Testing at available openings may be used to isolate the source in addition to the techniques previously mentioned. Many times the leak is found at the intersection of the foreign conduit and a gas line.

(j) Pinpointing a leak entering an underground conduit, sewer, or drain may require the investigation to extend to the first subsurface structure, in each direction, which has no readings.

(k) When the pattern of the CGI readings has stabilized, the barhole with the highest reading will usually pinpoint the gas leak.

(l) The responder should test with soap forming solution where piping has been exposed, particularly to locate smaller leaks.

6.2 Bonding Steel Pipe (Electrical Continuity)

Refer to 1-D, *Safety*, Section 19.0.

6.3 Handling Static Electricity when Installing or Repairing Plastic Pipe

Refer to 1-D, *Safety*, Section 20.0.

6.4 Corrosion Control on Repaired Pipe

Refer to 2-O, *Corrosion Control*.

7.0 REPAIR OF LEAKS

In **Massachusetts**, there shall be written procedures for any maintenance or repairs on intrastate mains and transmission lines operating in excess of 200 psig pipeline. The materials and equipment used for maintenance or repair shall be suitable for the MAOP of the pipeline; and personnel shall be trained in the use of those materials and equipment before any maintenance or repairs are performed. [MA 220 CMR 109.13(6)]

7.1 Leaks on Buried Piping

(a) Perform appropriate leak investigation in accordance with Section 4.0 above.

(b) Once the leak is pinpointed, (See Section 6.1 above) the gas pipeline shall be exposed, and the flow of escaping gas shall be stopped as soon as practicable.

(c) The *One-Call system* shall be used on scheduled leak repairs and on other leak repairs, if time permits, to locate other underground structures in the area of the leak before excavation begins. (See Procedure 2-G, Section 8.0)

(d) In making repairs to metallic mains and service lines, the following should be considered.

(1) Piping material (e.g., bare steel, coated steel, Cathodically protected steel, cast iron).

(2) Overall condition of the exposed pipe (e.g., pit depth and remaining wall thickness; whether there is corrosion damage, physical damage, or dents).

(3) Repair method (e.g., stainless steel band clamp, encapsulation device, steel pin weldment).

(4) Residual gas in the trench atmosphere.

(e) Regarding metallic mains:

(1) If a segment of metallic main shows signs of deterioration or mechanical damage, promptly notify the Distribution Manager, or designee, who shall determine whether the segment will be a candidate for further replacement.

(2) If the segment is in very poor condition, promptly notify the Distribution Manager, or designee, and request authorization to replace that segment. If a replacement is considered that would result in leaving a short section of old, unprotected pipe in place between new pipe segments, consideration should be given to replacing the short, old section.

(3) In Maine, A utility finding a leak on a bare steel service line shall replace the entire service line. [ME Puc 420.6D5]

(f) If a leak is repaired on a steel main, see the corrosion control requirements in Procedure 2-O, *Corrosion Control*.

(g) Record locations of repair fittings on the Leak Investigation Work Order.

(h) After the final site check is completed (see Section 7.2.1 below), backfill the excavation, restore the roadway surface (see Procedure 4-F, Sections 5.0 and 6.0), and fill bar holes with approved tar plugs before leaving the work area.

(i) For steel pipe, complete the *Coating Condition* and *Pipe Condition* sections on the Leak Investigation Work Order.

7.2 Leak Repair Follow-Up and Clearing Leaks

7.2.1 Final Site Check

(a) Once the repair is completed and gas is re-admitted to the affected section of pipe, the adequacy of the leak repair shall be checked before backfilling. [ME Puc 420.6D6] Repair fitting, clamp, or coupling shall be soap tested to ensure a proper repair.

(b) If applicable, buildings near the repaired pipeline shall be checked for indications of gas using a CGI.

(c) Road boxes, curb boxes, manholes, and bar holes in the area of the leak shall be rechecked with a CGI.

(d) Check the perimeter of the leak using a CGI

(e) If gas is detected in the areas in paragraphs (c) and (d) above, other than residual gas from the repaired leak, additional leaks could exist and shall be repaired and/or investigated, classified and properly documented. The repair crew shall not leave the site until there is no hazard to persons or property.

7.2.2 Leak Repair Recheck and Clearing Procedure

(a) Leak repairs on buried pipelines shall be rechecked within 30 days after the repair has been completed.

(b) Bar test the area where the leak has been physically repaired and throughout the original leak migration pattern. Sample the atmosphere in the bar holes with a CGI.

(c) A leak is considered to be effectively repaired when a CGI gas concentration reading of 0% is reached in the repair area.

(d) Except as addressed in Paragraph (e) below, a presence of gas in the repair area or migration pattern may indicate that a leak still exists in the repair location (and/or) additional leaks may exist in the surrounding area. Operating personnel should utilize training, experience and judgment in making this determination and any questions should be directed to the Distribution Manager or designee.

1. If it is determined that the original leak repairs were inadequate and additional repairs are needed then the existing leak I.D. should be returned to "active" status.

2. If it is determined that additional leaks are present then these leaks should be investigated, classified and documented.

3. Under certain circumstances the leak I.D. can be downgraded, consistent with the company downgrade procedure in Section 5.1.3.

(e) If gas is still present, but it is considered to be residual gas (gas remaining in the ground from the leak that had already been repaired), do as follows.

1. Note on the Leak Investigation Work Order form that the leak should be rechecked again in 30 days.

2. Continue to recheck the leak at approximate 30-day intervals until there is no indication of gas. Note the results on the Leak Investigation Work Order.

3. If after three inspections the leak is unable to be cleared then the leak will be returned to "active" status or new leak orders should be created.

8.0 ADDITIONAL PROVISIONS FOR LEAK REPAIR ON TRANSMISSION LINES

8.1 General [192.711] [MA 220 CMR 109.13(6)]

(a) This section covers additional provisions for repairs on transmission lines. It does not replace, but is in addition to, any other procedures that may apply to a specific situation.

(b) Immediate temporary measures shall be taken to protect the public whenever:

(1) A leak, imperfection, or damage that impairs its serviceability if found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and

(2) It is not feasible to make a permanent repair at the time of discovery.

(c) Permanent repairs shall be made as soon as feasible.

(d) Except as provided in Section 8.4(a)(3) below, a *welded patch* shall not be used as a means of repair.

8.2 Permanent Field Repair of Imperfections and Damages [192.713]

(a) Except a provided in paragraph (b) below, each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS shall be repaired as follows:

(1) If it is feasible to take the segment out of service, the imperfection or damage shall be removed by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment out of service, a full encirclement *welded split sleeve* of appropriate design shall be applied over the imperfection or damage.

(3) If the segment is not taken out of service, the operating pressure shall be reduced to a safe level during the repair operations.

(b) Submerged pipelines in inland navigable waters may be repaired by mechanically applying a *full encirclement split sleeve* of appropriate design over the imperfection or damage.

8.3 Permanent Field Repair of Welds [192.715]

(See Procedure 4-I, Section 5.2)

8.4 Permanent Field Repair of Leaks [192.717]

(a) Except as provided in paragraph (b) below, each permanent field repair of a leak on a transmission line shall be made as follows:

(1) If feasible, the segment of transmission line shall be taken out of service and repaired by cutting out a cylindrical piece of pipe and replacing it with pipe of similar or greater design strength.

(2) If it is not feasible to take the segment of transmission line out of service, repairs shall be made by installing a full encirclement welded split sleeve of appropriate design, unless the transmission line:

(A) Is joined by mechanical couplings; and

(B) Operates at less than 40 percent of SMYS.

(3) If the leak is due to a corrosion pit, the repair may be made by installing a properly designed bolt-on-leak clamp; or, if the leak is due to a corrosion pit and on pipe of not more than 40,000 psig SMYS, the repair may be made by fillet welding over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size.

(b) Submerged pipelines in inland navigable waters may be repaired by mechanically applying a full encirclement split sleeve of appropriate design over the leak.

8.5 Testing of Repairs

8.5.1 Testing of Replacement Pipe [192.719(a)]

If a segment of transmission line is repaired by cutting out the damaged portion of the pipe as a cylinder, the replacement pipe shall be tested to the pressure required for a new line installed in the same location. This test may be made on the pipe before it is installed.

8.5.2 Testing of Repairs Made by Welding [192.719(a)]

Each repair made by welding in accordance with Sections 8.2, 8.3, or 8.4 above shall be examined in accordance with Procedure 4-I, Section 4.0.

9.0 RECORDS [192.709]

9.1 Leak Repairs

(a) Leak repairs shall be recorded on the Leak Investigation/Repair Work Order.

(b) Completed Leak Investigation/Repair Work Orders for repairs on pipe shall be retained for as long as the pipe remains in service, and completed forms for pipeline system components other than pipe shall be retained for 5 years.

9.2 Plastic Pipe Data Collection and Sharing Initiative

Each natural gas utility shall participate in the Plastic Pipe Data Collection and Sharing Initiative and report each discovered incident of plastic pipe failure as prescribed in the Initiative to the Maine PUC Gas Safety Manager, and the American Gas Association Plastic Pipe Ad Hoc Committee. [ME Puc 420.7B]

10.0 EVACUATION PROCEDURE

Evacuation of a building shall be considered any time a concentration of gas exists in the open atmosphere inside the building and/or at the discretion of the first responder in the interest of public safety.

(1) Immediately leave the building with all occupants through the entrance you had just entered and close the doors behind you.

(2) Notify the dispatcher of the existing conditions as soon as circumstances will permit. Whenever a building must be evacuated, instruct Gas System Dispatch to notify the Supervisor, Fire Department and/or Police Department. Request that other utilities (electric & telephone) be disconnected.

(3) Turn off the gas to the premises by the safest and fastest method (e.g., curb valve, meter valve, main valve, and pipe squeeze-off tool). Do not enter the building to do so.

(4) If possible, ventilate the premises without jeopardizing safety. Refer to Section 11.0, *Ventilation Procedure*.

(5) Standby outside the premises and prevent any person from entering the area until it is safe to do so. Ensure all personnel maintain a safe distance from the structure and establish a safe zone.

11.0 VENTILATION PROCEDURE

Contact Supervisor for instructions regarding ventilation.

12.0 COMBUSTIBLE GAS INDICATORS (CGIs)

A combustible gas indicator (CGI)) shall be used to determine whether an explosive atmosphere is present. It is the First Responder or Technician's responsibility to insure that his/her combustible gas indicator is in operating condition at all times.

Operation and maintenance of CGI units will be per manufacturer instructions and recommendations. Refer to Section 2-V, *Equipment Maintenance and Calibration*.

13.0 EMERGENCY STANDBY PROCEDURE

13.1 General

(a) The First Responder will stand by at the scene of a leak investigation to insure that safe conditions are maintained and to assist the Distribution Department until properly released. The name of the supervisor or designee releasing the First Responder will be noted on the Work Order.

(b) The responsible Service supervisor is to be notified by Gas System Dispatch whenever the stand-by is to be of a long duration.

(c) Readings obtained with the combustible gas indicator will be recorded on the Leak Investigation documentation, giving percentage of LEL or percentage of gas. Proper documentation will be maintained for each building that was investigated. Be sure to include each time the building was checked and the readings found.

13.2 While Waiting for the Distribution Department

(a) While waiting for assistance from the Distribution Department, the first responder will check for indications of a gas leak using a combustible gas indicator in all buildings, water boxes, catch basins, and substructures to the extent of the gas migration area, in both directions, on both sides of the street beyond the last location where gas was detected.

(b) If the condition warrants, ventilate. If substructures must be ventilated, don't leave them unguarded. Report all such openings to the Distribution Department upon their arrival. The first responder will brief the Distribution Department personnel of the action already taken and assist them in the investigation of the leak.

13.3 Extended Standby

(a) When a First Responder is assigned to standby on a street leak, the First Responder should not underestimate the importance of their responsibilities. Their duty is to protect the public and the Company's interest. The First Responder is not to issue any statements to the press or any other parties not affiliated with the Company.

(b) While standing by, the First Responder will continually check all buildings in the affected area and make sure that the ventilation is adequate. Occupants of the buildings are to be instructed not to close any windows or doors which were opened for ventilation.

(c) If a build-up of gas occurs in a building, immediately notify the Distribution Supervisor/Gas System Dispatch. The building may have to be evacuated to insure the safety of its occupants. This is extremely important if the building offers little means of ventilating.

(d) The first responder will gather all pertinent data regarding access to buildings, availability of keys, telephone numbers, number of apartments in the buildings, stores and the location of any gas equipment. All such information will be recorded on the Leak Investigation documentation.

(e) After the street leak has been repaired, the First Responder will check to be sure that gas is not still seeping into the building. The first responder will close all ventilation sources and continue to check for a minimum of thirty (30) minutes using the combustible gas indicator. If there is no evidence of a gas build-up, he will secure all doors or windows, which were opened for ventilation, restore all service to the customer by relighting all gas appliances that were shut off, and return all electrical switches to their normal positions. Record all pertinent data on the Leak Investigation documentation.

(f) If the first responder at the scene is relieved, the original responder will brief the oncoming personnel of the situation, giving them the Leak Investigation documentation and pointing out any special arrangements or conditions recorded thereon. The oncoming personnel will be taken into all the buildings to show them the affected areas where the gas is entering and inform them of the procedure being used to ventilate. The First Responder being relieved will complete Leak Investigation documentation by recording their name and stating that he/she has passed on the work orders with the addresses of the buildings involved to the relief person.

Figure 2-N-1 - Letter from SENSIT Technologies

SENSIT Technologies

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www.
ISO

February 1, 2012

Mr. Dan Golden
Unitil
285 John Fitch Hwy.
Fitchburg MA 01420

Re: Vehicle Speed using PMD w/auxiliary pump

Dear Dan,

Thank you for your continued support of Sensit Technologies products over the years. F request please find our recommended vehicle speed when using Sensit PMD w associated auxiliary pump assembly.

Sensit recommends a speed of 5-10 miles per hour (mph) during normal climate cor During times of excessive wind, rain and snow speeds less than 5 mph should be mainta

If there are any questions regarding this information please feel free contacting me direc

Thank you for your trust in Sensit Technologies.

Best regards,
Sensit Technologies

J. Scott Kleppe
President

ATTACHMENT E

GM Appendix G-192-11 - 7 Pinpointing

7.1 Scope.

Pinpointing is the process of tracing a detected gas leak to its source. It should follow an orderly systematic process that uses one or more of the following procedures to minimize excavation. The objective is to prevent unnecessary excavation which is more time consuming and costly than time spent pinpointing a leak.

7.2 Procedure.

(a) The migration of gas should be determined by establishing the outer boundaries of the indications. This will define the area in which the leak will normally be located. These tests should be made with a CGI without expending excessive effort providing sample points.

(b) In an urban environment, sampling is recommended at available openings (e.g., manholes, valve boxes) in the area. Testing such structures provides advantages in determining migration when pinpointing a leak, such as the following.

(1) Identifying the spread through efficient use of existing structures, thus minimizing barholes.

(2) Reducing the risk of damaging other utilities during the investigation.

(3) Expediting the investigation.

(c) Foreign facilities in the area of search should be identified. The operator should look for evidence of recent construction activities that could have contributed to the leakage. Gas may also migrate and vent along a trench or bore hole provided for other facilities. Leaks could occur at the intersection of the foreign facility and the gas pipeline. Particular attention should be given to these intersections.

(d) Evenly spaced bar or test holes should be used over the gas line suspected to be leaking. All barholes should be of equal depth and diameter (and down to the pipe depth where necessary) and all CGI readings should be taken at an equal depth in order to obtain consistent and worthwhile readings. Using only the highest sustained readings, the gas can be traced to its source by identifying the test holes with the highest readings.

(e) Frequently, high readings are found in more than one barhole and additional techniques are necessary to determine which reading is closest to the probable source. Many of the barhole readings will normally decline over a period of time but it may be desirable to dissipate excess gas from the underground locations to hasten this process. Evaluation methods should be used with caution to avoid distorting the venting patterns.

(f) Once underground leakage has been identified, additional holes and deeper holes should be probed to more closely bracket the area. For example, test holes may be spaced six feet apart initially and then the six foot spacing between the two highest test holes might be probed with additional test holes, with spacing as close as twelve inches.

(g) Additional tests include taking CGI readings at the top of a barhole or using manometer or bubble forming solution to determine which barhole has the greatest positive flow. Other indications are dust particles blowing from the barholes, the sound of gas coming from the barhole or the feel of gas flow on a sensitive skin surface. On occasion, sunlight diffraction can be observed as the gas vents to the atmosphere.

(h) When gas is found in an underground conduit, testing at available openings may be used to isolate the source in addition to the techniques previously mentioned. Many times the leak is found at the intersection of the foreign conduit and a gas line. Particular attention should be given to these locations.

(i) Testing at available openings may be used to isolate the source in addition to the techniques previously mentioned. Many times the leak is found at the intersection of the foreign conduit and a gas line. Particular attention should be given to these locations.

(j) Pinpointing a leak entering an underground conduit, sewer, or drain may require the investigation to extend to the first subsurface structure, in each direction, which has no readings. See 5.3(i) above.

(k) When the pattern of the CGI readings has stabilized, the barhole with the highest reading will usually pinpoint the gas leak.

(l) The operator should test with bubble forming solution where piping has been exposed, particularly to locate smaller leaks.

7.3 Precautions.

(a) When placing barholes for testing, consideration should be given to barhole placement and depth to minimize the potential for damage to other underground facilities and possible injury to personnel conducting the investigation.

(b) Unusual situations may complicate these techniques on some occasions. They are unlikely, but possible. For example, multiple leakage can be occurring which gives confusing data. The area should be rechecked after repairs are completed to eliminate this potential. Gas may occasionally pocket and give a strong indication until the cavity has been vented. Foreign gases, such as gas from decomposed material, can occasionally be encountered. This is characterized by fairly constant CGI readings between 15 percent and 30 percent gas throughout the area. Indications of gas detected in sewer systems should be considered migrating gas leakage until proven otherwise by test or analysis.

(c) When pinpointing leakage where the gas is heavier than air (LP gas), the gas will normally stay low near the pipe level, but may flow downhill. LP gases usually do not diffuse or migrate widely so the leak is generally close to the indication. If the gas is venting into a duct or sewer system, it can travel considerable distance.

Table 2 - Available Methane Detection Technologies

The following technologies are currently commercialized for use in methane leak detection. The information in the table depicts typical or nominal values/properties/characteristics contained in current manufacturers' literature. Operators should consult instrument manufacturers for appropriate application and limitations of available instrument technologies.

Technology	Typical Application	Sensitivitya	Rangea	Sampling Method	Advantages	Limitations
Catalytic (Pellistor)	1	50 ppm 0.1-1% LEL 1% VOL	0.1-100% LEL	Vacuum pump Hand aspiration	Multi-gas options for confined space entry.	• Sensors may be damaged by shock or vibration. • Loss of sensitivity when exposed to paint, lacquer, or varnish vapors.
Thermal Conductivity	1	2.5% VOL	0-100% VOL	Vacuum pump Hand aspiration	Multi-gas Capability.	• Exposure to high concentrations may saturate the sensor.
Amplified Thermal	1	5 ppm	5-1,000 ppm	Vacuum pump	Fast response.	• Zero stability dependent on temperature and moisture.

Conductivity						• Temperature change, dust, and moisture may cause false detection.
Semiconductor	2	1-100 ppmb	0-1,000 ppm	Diffusion	Fast response.	• Zero stability dependent on temperature and moisture. • Can be damaged by water.
Flame Ionization	2, 3	1 ppm	0-10,000 ppm	Vacuum pump	Fast response. Vacuum pump system will draw residual gas from soil surface or cavity.	• Venturi draw systems are slower responding. • Will detect all volatile organic compounds (VOCs) unless special filters are used. • Requires external hydrogen fuel. • Calibration affected by temperature and humidity. • High concentration gas will cause sensor flame out. • Requires warm-up time to become stable.
Open Path IR TDLAS	2, 3c, 4	5 ppm-meter	0-100,000 ppm-meter	Atmospheric open path laser scanning of up to 100 ft.	Remote detection of low leak levels, faster survey, improved operator safety, methane specific detection. Scanning of confined space without entry.	• Low flowing leaks may not produce a detectable plume.
Closed Path Bifringent IR	1d, 2, 3	1 ppm	0-2,500 ppm 0-100% VOLb	Vacuum pump with sample cell	Low level leak detection, methane specific, no fuel gas, extended measurement range, very fast response.	• Requires warm-up time to reach full sensitivity.
Closed Path Bifringent IR (Continued)	3	1 ppm	0-250 ppm	Atmospheric closed path	Low level leak detection, methane specific, no fuel gas, fast mobile survey speed.	• Weather related conditions may affect detector (e.g., snow, sloppy road conditions). • Requires warm-up time to reach full sensitivity.
Closed Path IR Laser	1, 2, 3	1-100 ppmb	0-1,000 ppm 0-100% VOL	Vacuum pump with sample cell	Low level leak detection, methane specific, no fuel gas, extended measurement range.	• Dust contamination in sample cell will severely affect sensitivity. • Response rate and sensitivity vary by sample cell path length and flow design. • Slower response.
Open Path Passive IR Imaging	4	Unknown	N/A	Atmospheric open path	IR image of venting gas.	• Effective for moderate to large size leaks, difficult to image under certain ambient conditions.

(a) Specifications represent typical performance levels of the technology and implementation approach. Actual instrument specifications and performance may vary by manufacturer and product.

(b) Varies widely by manufacturer.

(c) Systems are currently under development. Currently in use on transmission line survey

(d) Systems are currently under development.

Applications Key

1. Leak investigation and classification. Typical instrument requirements are to measure percent gas

or LEL to classify the severity of a leak. Instruments are typically rated "Intrinsically Safe." Typical measurement may be taken within a barhole or in the air of an area with a known leak.

2. Walking leak survey. Typical instrument requirements are to measure very low concentration levels with fast responding sensors. Typical measurements are taken while walking and searching with the instrument.
3. Mobile leak survey. Typical instrument requirements are to measure very low concentration levels with fast responding sensors. Typical measurements are taken while driving in a vehicle or ATV and searching with the instrument.
4. Gas gathering and production facilities, compressor station leak survey. Typical instrument requirements are to measure moderate to high concentrations from a remote distance.

Definitions

Open Path:	IR light passes through a naturally venting gas plume.
Closed Path:	IR light passes through sample chamber into which a vacuum pump draws gas.
Active IR:	IR beam is projected via a laser or other IR radiation source (e.g., LED, halogen lamp).
Passive IR:	IR light source is naturally occurring from sunlight or heat radiation.
Mid IR:	IR wavelengths in the 3-5µm (µm is micro-meter).
Near IR:	IR wavelengths in the 0.8-2µm.

Catalytic:

Catalytic works on the basis that gas molecules will combust when coming into contact with a heated platinum wire (coated with a catalytic material). The catalytic material will accelerate the oxidation reaction, thus raising the temperature of the platinum wire. As the platinum wire heats up, the change in resistance is measured. The amount of resistance change is proportional to the gas concentration. Typically, two sensor beads are used (sample and reference).

Thermal Conductivity:

Thermal conductivity works on the basis of passing a sample of gas over a heated thermistor. The thermistor will change resistance relative to the thermal conductivity of the gas. A reference thermistor is normally used to generate a relative comparison. The resistance change is proportional to the gas concentration.

Amplified Thermal Conductivity:

Amplified thermal conductivity is the same principle as "Thermal Conductivity" but with additional electronic amplification to increase the response signal.

Semiconductor:

Semiconductor sensors work on the basis that a tin dioxide (SnO_2) material (when heated to a specific temperature (e.g., at 400°C) for hydrocarbon detection) will change resistance as it interacts with the gas. The resistance change is non-proportional to gas concentration.

Flame Ionization:

Flame ionization works on the basis that gas molecules are positively charged by burning in a high temperature hydrogen flame. The ions are then collected on an electrode. The rate of charged particles collected is proportional to the gas concentration.

Open Path IR TDLAS (Tunable Diode Laser Absorption Spectroscopy):

Open path IR TDLAS works on the basis of an IR laser (~1.6μm for methane) sweeping through a naturally venting gas plume from a remote distance. As the IR laser passes through the plume, the gas will absorb a portion of the light. Absorption spectroscopy is used to measure the amount of absorption. The amount of absorption is proportional to the gas concentration and the path length through the gas.

Closed Path Bifringent IR:

Bifringent IR works on the basis that gas molecules absorb infrared light at specific wavelengths (~3.3μm for methane). A gas sample is passed through the light path in which a portion of the IR light is absorbed. Optical processing by a bifringent (Etalon) crystal is used to measure the amount of absorption. The amount of absorption is proportional to the gas concentration and the path length through the gas.

Closed Path IR Laser:

Closed path IR lasers work on the basis of passing a near IR laser tuned to a specific gas absorption wavelength (~1.6μm) through a gas sample cell. The amount of absorption is proportional to the gas concentration and the path length through the gas. In order to increase the sensitivity, multiple passes through the cell are used to increase the path length. There are a number of laser, gas sample cell design, and signal processing approaches.

Open Path Passive IR Imaging:

IR Imaging works on the basis that gas molecules absorb infrared light at specific wavelengths (3-5μm). A gas imager uses a specialized set of lenses, IR filters, and photo detector array to measure the reduction of IR light relative to the background. A video image is then displayed. In some systems, additional post signal processing is used to enhance the contrast or to color the image.

TABLE 3a - LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 1

Grade	Definition	Action Criteria	Examples
1	A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. See §192.703(c).	Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous. *The prompt action in some instances may require one or more of the following. a. Implementation of emergency plan (§192.615).	1. Any leak which, in the judgment of operating personnel at the scene, is regarded as an immediate hazard. 2. Escaping gas that has ignited. 3. Any indication of gas which has migrated into or under a building, or into a tunnel.

		b. Evacuating premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area by removing manhole covers, barholing, installing vent holes, or other means. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments.	4. Any reading at the outside wall of a building, or where gas would likely migrate to an outside wall of a building. 5. Any reading of 80% LEL, or greater, in a confined space. 6. Any reading of 80% LEL, or greater in small substructures (other than gas associated substructures) from which gas would likely migrate to the outside wall of a building. 7. Any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property.

TABLE 3b - LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 2

Grade	Definition	Action Criteria	Examples
2	A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	Leaks should be repaired or cleared within one calendar year, but no later than 15 months from the date the leak was reported. In determining the repair priority, criteria such as the following should be considered. a. Amount and migration of gas. b. Proximity of gas to buildings and subsurface structures. c. Extent of pavement. d. Soil type, and soil conditions, such as frost cap, moisture and natural venting. Grade 2 leaks should be reevaluated at least once	*A. Leaks Requiring Action Ahead of Ground Freezing or Other Adverse Changes in Venting Conditions.* Any leak which, under frozen or other adverse soil conditions, would likely migrate to the outside wall of a building. B. *Leaks Requiring Action Within Six Months* 1. Any reading of 40% LEL, or greater, under a sidewalk in a wall-to-wall paved area that does not qualify as a Grade 1 leak. 2. Any reading of 100% LEL, or greater, under a

		every six months until cleared. The frequency of reevaluation should be determined by the location and magnitude of the leakage condition. Grade 2 leaks may vary greatly in degree of potential hazard. Some Grade 2 leaks, when evaluated by the above criteria, may justify scheduled repair within the next 5 working days. Others will justify repair within 30 days. During the working day on which the leak is discovered, these situations should be brought to the attention of the individual responsible for scheduling leak repair. On the other hand, many Grade 2 leaks, because of their location and magnitude, can be scheduled for repair on a normal routine basis with periodic reinspection as necessary.	street in a wall-to-wall paved area that has significant gas migration and does not qualify as a Grade 1 leak. 3. Any reading less than 80% LEL in small substructures (other than gas associated substructures) from which gas would likely migrate creating a probable future hazard. 4. Any reading between 20% LEL and 80% LEL in a confined space. 5. Any reading on a pipeline operating at 30 percent SMYS, or greater, in a class 3 or 4 location, which does not qualify as a Grade 1 leak. 6. Any reading of 80% LEL, or greater, in gas associated substructures. 7. Any leak which, in the judgment of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair.

TABLE 3c - LEAK CLASSIFICATION AND ACTION CRITERIA - GRADE 3

Grade	Definition	Action Criteria	Examples
3	A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	These leaks should be reevaluated during the next scheduled survey, or within 15 months of the date reported, whichever occurs first, until the leak is regraded or no longer results in a reading.	*Leaks Requiring Reevaluation at Periodic Intervals* 1. Any reading of less than 80% LEL in small gas associated substructures. 2. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building.

3. Any reading of less than 20% LEL in a confined space.